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IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827 **NOTICE OF FILING REPORT**

Arizona Corporation Commission Staff ("Staff") hereby files its report regarding its inquiry into Arizona Public Service Company's fuel and purchased power procurement and costs. The attached report is a public version with confidential information redacted. A confidential version of this report will be provided under seal to the commissioners, their assistants, the assigned administrative law judge, APS, and any parties who have signed protective agreements with APS in this matter. Because of the length of the report, Staff intends to serve the parties electronically. Staff will be happy to provide a hard copy of the report upon request.

RESPECTFULLY SUBMITTED this 1st day of September, 2006.

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Final Audit Report
APS Fuel and Purchased Power Procurement and Costs
Non-Confidential Version

(Redacted Information Shaded)

Presented to:

Arizona Corporation Commission
Utilities Division

Presented by:

The Liberty Consulting Group

August 31, 2006

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I. Introduction

A. Project Scope and Objectives

The Staff of the Arizona Corporation Commission ("ACC") issued a November 16, 2005 RFP seeking an audit of the fuel and purchased power procurement practices and costs of Arizona Public Service Company. The RFP sought an examination and analysis of the management and operations of the utility's fuel and purchased power functions and the formulation of any appropriate recommendations. The RFP asked that the audit address:

- Organization structure, responsibilities, and staffing
- Policies, procedures, systems, and tools
- Procurement approach, methods, and decisions.

The RFP identified a series of work elements within these broad areas. The Liberty Consulting Group ("Liberty") responded to this RFP with a December 9, 2005 proposal to perform the audit. The ACC selected Liberty to perform the audit. The following report describes the examination and analyses that Liberty undertook, the findings and conclusions it has reached, and the recommendations that Liberty considers appropriate for addressing those conclusions.

B. Company Background

Arizona Public Service Company ("APS" or "the Company") is an electric utility based in Phoenix, Arizona. APS operates as the largest subsidiary of Pinnacle West Capital Corporation ("PWCC"), a holding company with over $11 billion in assets and $3 billion in annual revenues. APS utility operations generated 75 percent of consolidated PWCC operating revenues in 2005 -- up by 3 percent from 2004. Over the past three years, the operating revenues of the other two PWCC business lines (non-utility marketing/trading and real estate) have declined moderately. A factor in the non-utility marketing/trading sector's contraction has been the placement of former merchant units into the APS utility generation mix, as the Company has moved back (albeit under a changed paradigm) in the direction of vertically integrating utility electricity services. PWCC does not view marketing/trading as a longer-term business priority in light of marketplace changes in Arizona particularly and in the region generally. The following table shows the relative contribution of APS to consolidated operating revenues.

Table I.1 PWCC Operating Revenues

	2005	2004	2003	2002	2001
OPERATING RESULTS					
Operating revenues:					
Regulated electricity segment	**$ 2,237,145**	$ 2,035,247	$ 1,978,075	$ 1,890,391	$ 1,984,305
Marketing and trading segment (a)	**351,558**	400,628	391,196	286,879	469,784
Real estate segment (a)	**338,031**	350,315	361,604	201,081	168,908
Other revenues	**61,221**	42,816	27,929	26,899	11,771
Total operating revenues	**$ 2,987,955**	$ 2,829,006	$ 2,758,804	$ 2,405,250	$ 2,634,768

APS has averaged a 3.8 percent increase in customers for the past three years. In 2004, APS was serving approximately 990,000 customers in 11 of Arizona's 15 counties. Customer numbers surpassed 1,000,000 in 2005, during which APS experienced load growth of 9.3 percent. Strong growth is not a recent phenomenon at APS. The Company has been the second-fastest growing utility in the United States since 1999. APS projects that annual growth rates will remain at 2.8 percent for customer numbers and will run at 3.8 percent for total usage. PWCC's most recent annual report illustrates APS's dramatic growth in customers and in usage per customer. Fuel costs have risen strongly as well. The following tables summarize these areas of growth.

Figure I.2 APS Annual Customer Growth and Electricity Use

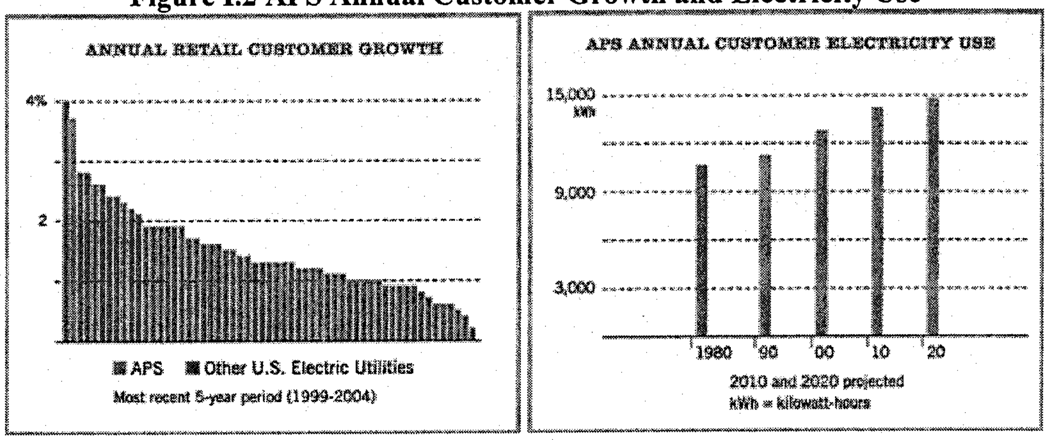


Figure I.3 Fuel Cost Increases

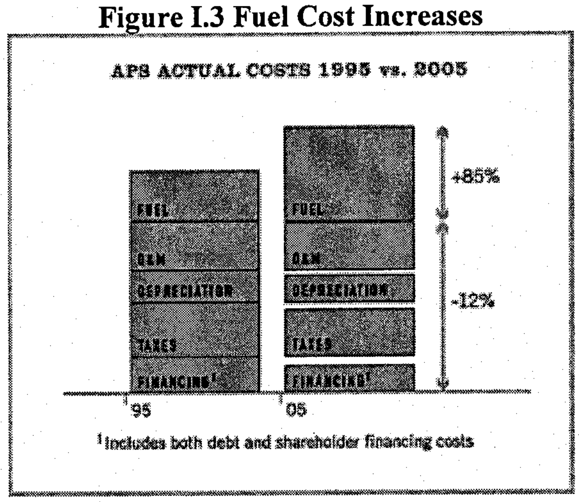


Table I.4 APS Annual Fuel Expense

Year	Fuel Expense
2005	$595 million
2004	$567 million
2003	$517 million

The nature of APS fuel contracting (particularly long-term coal contracts and nuclear fuel arrangements) also produces a very substantial forward commitment. Take-or-pay commitments in its coal contracts through 2024 total $1 billion, and have a present value of $600 million.

New APS rates became effective April 1, 2005, following a settlement agreement. The resulting total revenue requirement increase was $75.5 million. The settlement agreement also provided for the transfer of four APS-affiliate owned gas-fired generation units (totaling 1,780MW) into the APS rate base. The approved settlement agreement implemented a Power Supply Adjustor ("PSA") that provides for fuel (including nuclear fuel) and purchased power cost recovery.

APS is responsible for managing 10,400 MV of capacity at 11 generating stations, including Palo Verde. The following table lists the fossil stations, which formed the principal focus of this audit.

Table I.5 APS Generating Stations and Fuel Type

Station Name	Fuel Type	Station Name	Fuel Type
Four Corners	Coal	Redhawk	Natural Gas
Cholla	Coal	Sundance	Natural Gas
Navajo	Coal	Saguaro	Natural Gas
Douglas	Oil	West Phoenix	Natural Gas
Ocotillo	Natural Gas	Yucca	Natural Gas

APS jointly owns much of its generation with others; APS has responsibility for operation of more capacity than it owns. Its ownership totals 6,415MW, which consists of the following components and percentages of total ownership:

- Palo Verde Nuclear Generating Station ("Palo Verde"): 1,164MW (18.1 percent of total)
- Natural gas: 3,411MW (53.2 percent)
- Coal: 1,835MW (28.6 percent)
- Solar: the remaining 5MW (0.1 percent).

A brief description of the major units follows:

- Four Corners: five coal-fired units
  - 2,040MW total capability
  - 782MW share owned by APS
  - Owned by six southwest utilities
  - Operated by APS
  - Located on the Navajo Indian Reservation west of Farmington, New Mexico
  - Uses low-sulfur coal from the nearby Navajo mine
- Cholla: four coal-fired units
  - 995MW total capability
  - Three units (with a total capability of 615MW) owned by APS
  - Fourth unit (with a capability of 380MW) owned by PacifiCorp
  - Operated by APS
  - Subject to a seasonal exchange agreement under which APS receives power during its summer peak and provides power during PacifiCorp's winter peak
  - Uses coal from the McKinley Mine in New Mexico
- Navajo: three coal-fired units
  - Each unit has a 750MW capability
  - Owned by partnership of five utilities and the U. S. Bureau of Reclamation

  - APS share is 14 percent
  - Operated by Salt River Project
  - Located on the Navajo Indian Reservation near Page, Arizona
  - Supplied by a Navajo and Hopi Indian Reservations mine at Black Mesa, Arizona
- Redhawk: two gas-fired, combined cycle units
  - Each with a capability of 530MW
  - Owned and operated by APS
  - Began operating in mid-2002
  - Located near the Palo Verde Nuclear Generating Station west of Phoenix
- West Phoenix: seven gas-fired units
  - Two combustion turbine units and five combined-cycle units
  - Owned and operated by APS
  - 1,000MW combined capability
  - Located in southwest Phoenix
- Ocotillo: four units
  - Two steam and two combustion turbine units
  - Combined capability of 340MW
  - Operated and owned by APS
  - Located in Tempe, Arizona
- Sundance: one simple-cycle gas-fired unit
  - 10 quick-start combustion turbines with a combined 450MW total capability
  - Located in Coolidge, Arizona
  - Owned and operated by APS
- Saguaro: five gas-fired units
  - Two steam units and three combustion turbine units; 395MW total capability
  - Located north of Tucson, Arizona
  - Owned and operated by APS
- Douglas: one oil-fired unit
  - Combustion turbine peaking unit with a capability of 16MW
  - Located in Douglas, Arizona
  - Owned and operated by APS
- Yucca: four gas-fired units
  - Combustion turbine units with a combined capability of 150MW
  - Located near Yuma, Arizona
  - Owned and operated by APS
  - Also includes an Imperial Irrigation District combustion turbine and steam unit
- Solar
  - Total capacity of all solar plants is about 5MW.

C. Audit Work Summary

The audit of APS fuel and purchased power procurement practices and costs began with the issuance of a first set of Liberty and Staff data requests on February 3, 2006. Liberty and Staff submitted nine sets of data requests consisting of 226 questions. Company responses were generally timely and responsive. The APS team assigned to assist in coordinating communications with Liberty and the Staff acted constructively to resolve uncertainties, assure complete answers, and support logistics needs. The Liberty team conducted initial interviews during the week of March 27, 2006. APS was responsive to requested interview subjects and topics, with one exception. Liberty found interviewees direct and forthcoming in responding to questions, and seemingly mindful of the importance of Commission access to and understanding of fuel and energy management at APS.

The exception to access to personnel involved the members of the board of directors. APS declined to make them available for interviews. APS did offer access to board minutes and the views of senior executives on what role the directors play in fuel and energy matters and how they exercise that role. Liberty's standard audit practice, however, is to discuss with directors in person what information they consider important and how they use it to oversee important areas of operations. Liberty could not address the directors' role in the manner planned. Liberty did ultimately gain sufficient information to conclude that there was no failure of information flow to the board, but believes that there should be future acceptance by APS of the propriety of direct communication with directors.

Liberty's team also conducted on-site work observations and inspections at the West Phoenix and Redhawk Plants to address operations issues. Liberty did the same at the Cholla and the Four Corners Generating Station coal handling areas, in order to observe and discuss coal-handling operations with station personnel. Liberty also directly observed work processes at the Four Corners coal lab, and discussed operations with lab personnel. Liberty examined operations and questioned APS personnel on the trading floor where dispatch, power sales and purchases, gas transportation management, and hedging transactions take place. This location includes PWCC's non-utility trading operations. This inspection included the front office (where actual trading takes place) and the middle and back offices (where accounting and controls related to energy transacting take place). Liberty also conducted phone interviews with APS employees to discuss follow-up questions arising from fieldwork, data gathering and analysis.

D. Report Structure

The following list summarizes the structure of this audit report:

- *Chapter One*: Introduction
- *Chapter Two*: Goals, Strategies, Organization, Policies, and Procedures
- *Chapter Three*: Fuel Management
- *Chapter Four*: Fuel Contracts
- *Chapter Five*: Hedging and Risk Management
- *Chapter Six*: Forecasting and Modeling
- *Chapter Seven*: Plant Operations
- *Chapter Eight*: Purchased Power and Off-system Sales
- *Chapter Nine*: Nuclear Fuel
- *Chapter Ten*: Financial Audit of PSA Costs.

Chapters Two through Ten address the work elements specified by the RFP. Each of those chapters sets forth a description of the scope it addresses. It then describes the factual information and observations (*Findings*) applicable to each area or issue examined. Each chapter then proceeds to set forth the conclusions reached by Liberty from those facts and about Company performance in each material performance area. Those conclusions specify where Liberty considered performance already to be effective and those areas where Liberty identified opportunities for performance improvement. The conclusions would also have expressed any Liberty opinions that performance failed to meet the standards of good utility practice, prudence, and reasonableness.

This audit report provides a recommendation specifically identifying what actions APS should take to address the issue underlying each conclusion that identified an opportunity for improvement. The report cross-references each recommendation to its underlying conclusion. Liberty has also assigned to each recommendation a ranking of between "1" (representing those that should be implemented with greatest dispatch) and "3" (representing those whose completion has the relatively lowest implementation priority). The following summary lists all of the audit's conclusions and recommendations, and provides the cross referencing and recommendation rankings.

E. Conclusions and Recommendations Summary

Chapter II. Organization, Staffing, and Controls

Conclusions:

1. Personnel in the fuel and power procurement have solid analytical skills and sound experience appropriate to meeting objectives and responsibilities.

2. Job descriptions for personnel in fuel and power procurement are current, and adequately address current responsibilities.

3. Communication within and among the fuel and power procurement organizations and upper levels of management is satisfactory.

4. The fuel and power procurement organizations have a satisfactory program for training and cross training of individuals within their departments.

5. APS maintains an appropriate decision matrix, or chart of approval authorities.

6. The program for employee training and compliance monitoring under the Code of Conduct is satisfactory.

7. The fuel and power procurement organizations have satisfactory procedures for many of the specific functional areas within these organizations, but Fuel Procurement does not have sufficient procedures for fuel contract management and administration. (*Recommendation #1*)

8. Documentation of fuel and power procurement and supply management activities is satisfactory.

9. The APS Audit Services group conducts regular and appropriate internal audits of fuel and power procurement functions.

10. The Company's procedures for accepting offers of gas supply are not sufficiently formal. *(Recommendation #2)*

11. Senior executive management has routinely provided to the board of directors substantial information about fuel, energy, and plant operations performance.

12. Available summaries of the board members' backgrounds show sufficient experience in matters relevant to utility fuel and energy management; however, Liberty was not able to determine through interviews with them what specific knowledge and experience they bring to bear or what values, criteria, performance indicators, and critical decision/judgment points they apply. *(Recommendation #3)*

13. The board's risk management role as defined in written policies and procedures is sound and the risk management program produces effective performance and status reports.

Recommendations:

1. Develop a complete set of procedures related to the management and administration of coal contracts. (*Conclusion #7; Priority 3*)

2. Audit and revise procedures for acceptance of offers for gas supply. *(Conclusion #10; Priority 3)*

3. Secure an understanding with APS that Commission auditing includes access to members of the board of directors. *(Conclusion #12; Priority 3)*

Chapter III. Fuel Management

Conclusions:

1. APS has effectively administered coal contracts.

2. Manual processes in handling coal weight information are not efficient. (*Recommendation #1*)

3. APS procedures for taking samples of coal at the Four Corners Station are sound.

4. APS has undertaken an appropriate program to automate the coal-sample analysis data-management process at the Four Corners laboratory; the program should be in place imminently.

5. The Fuel Procurement Department has an effective process for monitoring supplier performance; the performance of these suppliers has been satisfactory.

6. The Fuels Department appropriately manages coal inventory, but its recent reduction in the inventory target for Regular Coal at the Cholla Station has been too large. *(Recommendation #2*

7. APS has taken appropriate action in response to recent variances between coal inventory book values and the results of physical inventory surveys.

8. APS has appropriately sought beneficial uses and sales of coal combustion by-products.

9. APS has appropriately sought alternative means for disposal of coal combustion by-products at Four Corners when faced with significantly increased disposal costs from BHP.

10. APS's historical approach to gas supply management is typical, but current circumstances constrain its ability to address changes from full-requirements service from the pipeline. *(Recommendation #3)*

11. APS's pursuit of additional pipelines is appropriate.

12. APS's approach to buying fuel oils is reasonable.

Recommendations:

1. Streamline the procedures for handling of information on coal weights. *(Conclusion #2; Priority 3*)

2. Revise the inventory target for Regular Coal at the Cholla Station from 25 days of supply to 35 days of supply. *(Conclusion #6; Priority 3)*

3. Conduct a comprehensive analysis of gas purchasing and management under ELP's revised rate structure, and report to the Commission. *(Conclusion #10; Priority 1)*

Chapter IV. Fuel Contracts

Conclusions:

1. APS applied an appropriate process for the procurement of new long-term coal supplies for the Cholla Station.

2. APS's long-term coal supply agreements providing the primary supply to the Cholla and Four Corners Stations are effective.

3. APS's two short-term coal supply agreements for the Cholla Station are appropriate.

4. APS uses a sound process to contract for gas commodity.

5. The Company's efforts to develop alternatives to ELP have been appropriate.

6. APS's contracting process for fuel oils is appropriate.

Recommendations:

None.

Chapter V. Hedging and Risk Management

Conclusions:

1. APS has designed and it operates a sound hedging program.

2. The Company's program has been successful in meeting its primary objective.

3. The Company's hedging program will, however, prevent costs from falling. *(Recommendation #1)*

4. The segregation of utility and non-utility activities is not as complete as it should be. *(Recommendation #2)*

Recommendations:

1. Engage stakeholders in a discussion of hedging program objectives. *(Conclusion #3; Priority 2)*

2. Report to the Commission on the future plans for non-utility activities. *(Conclusion #4; Priority 1)*

Chapter VI. Forecasting and Modeling

Conclusions:

1. APS uses sufficiently accurate modeling to predict fuel and purchased power volume and cost.

2. APS has taken appropriate actions to ensure that it achieves least-cost total dispatch.

3. APS uses outside reviews appropriately to improve management and operations.

4. APS maintains adequate documentation to support regulatory oversight and review.

Recommendations:

None.

Chapter VII. Plant Operations

Conclusions:

1. The performance metrics of the base-loaded coal units demonstrate effective operation.

2. The performance metrics of the large gas units also demonstrate effective operation; however, performance metrics of these units have been adversely affected by their cycling as part of the APS dispatch order since April 2005.

3. The performance metrics of the less efficient gas units also demonstrate effective operation; however, performance metrics of the large gas units have been adversely affected by their cycling as part of the APS dispatch order since April 2005.

4. The capital expenditure and O&M expenditure patterns for the APS generating fleet have been consistent with operational requirements.

5. APS is not sufficiently reflecting the high net replacement power costs in its economic evaluations related to minimization of outage costs or spare parts procurement. (*Recommendation #1*)

6. The use of a 50/50 load forecast, coupled with the fast growth of the Phoenix Load Pocket, and system constraints of the Phoenix Load Pocket, makes achievement of targeted reserves less certain. (*Recommendation #2*)

7. The timing and layering of APS unit outage schedules follows industry practice, and is effective.

8. Major, scheduled outages at the base-load coal plants have had an appropriate length; however, outages at some of these plants from boiler leaks account for a conspicuously high percentage of net replacement power costs associated with these units. *(Recommendation #3)*

9. The level of operator and maintenance errors at Four Corners Unit #3 and Navajo Unit #3 is high. *(Recommendation #4)*

10. Improving West Phoenix Unit #5 availability is important to the dispatch and keeping net replacement power costs at minimum levels. (*Recommendation #5*)

11. APS has appropriately recognized the shift in the market paradigm brought about by inserting the former merchant units into the Company's dispatch order, and is appropriately dealing with Redhawk #1 and #2 and West Phoenix #5 issues involving the units and the need for re-engineering them for intermediate dispatch operation.

12. The large gas units have experienced representative outage frequency and duration, considering their recent in-service dates, generic problems, and the changes in mode of operation.

Recommendations:

1. Prepare and execute an action plan that will improve economic evaluations related to minimization of outage time. *(Conclusion #5; Priority 1)*

2. Analyze system reserve calculations using both a 50/50 and 90/10 load forecast, incorporating the constraints of the Phoenix Load Pocket. *(Conclusion #6; Priority 2)*

3. Evaluate the replacement of boiler sections at Four Corners #5, Navajo #2, and Navajo #3 in light of current high net replacement power costs. *(Conclusion #8; Priority 3)*

4. Conduct a centralized review of operator and maintenance errors at APS base-loaded coal plants and at Navajo, in order to assure that root causes are being correctly identified and addressed; determine the reasons why such errors appear to be concentrated at Four Corners Unit #3 and Navajo Unit #3. *(Conclusion #9; Priority 2)*

5. Implement for West Phoenix #5 the requirement for root cause analysis when generation is lost. *(Conclusion #10; Priority 3)*

Chapter VIII. Purchased Power and Off-System Sales

Conclusions:

1. The trading activities of APS M&T are based on sound hedging policies and procedures, and ensure that the procurement and sale of electric power is conducted in a manner that will meet least-cost dispatch guidelines.

2. APS effectively utilizes its portfolio of generating resources and power purchases to optimize value in the marketplace.

3. APS has developed the necessary documentation and tools to ensure that electric power trading can be conducted in accordance with the goal of achievement of the least-cost total dispatch.

4. APS Internal Auditing has been effective in monitoring the activities of electric power procurement and sale.

5. The APS internal documentation separating the activities of utility versus non-utility electric power trading is sufficient, but the external data presented in FERC forms does not make the appropriate distinctions between this information. *(Recommendation #1)*

6. The APS and non-utility trading operations are not sufficiently physically segregated. *(Recommendation #1)*

7. PWCC made some inappropriate commitments to trades using utility assets in 2005; but APS has eliminated them, transferred their margins to the utility accounts of APS, and begun changes to prevent the future use of utility assets by affiliates. *(Recommendation #2)*

8. The primary reason that sales for resale have produced smaller margins than those of neighboring utilities is APS's lower proportional levels of excess coal and nuclear generation.

Recommendations:

1. Clearly segregate utility and non-utility trading in all operations and reporting to ensure that utility trading is conducted to maximize utility opportunities. *(Conclusions #5 and #6; Priority 1)*

2. Complete the process of preventing future affiliate use of utility assets and examine means for continuing transmission optimization transactions through some form of sharing mechanism. *(Conclusion #7; Priority 1)*

Chapter IX. Nuclear Fuel

Conclusions:

1. APS conducts nuclear fuel procurement and management through an effective organization.

2. APS has developed and used effective procedures for procuring nuclear fuel.

3. APS uses an appropriate basis to account for its nuclear fuel costs for ratemaking purposes.

Recommendations:

None.

Chapter X. Financial Audit of PSA Costs

Conclusions:

1. APS's accounting systems are adequate and reasonably maintained to provide the necessary collection, reporting, and auditing of the PSA filings, and provide for reasonable testing.

2. APS audits, however, have yet to address PSA filing preparation. *(Recommendation #1)*

3. APS documents its filing information well, but lacks a formal written procedure addressing preparation of the monthly PSA filings. *(Recommendation #2)*

4. The monthly PSA filings were in general compliance with filing requirements and the sum total of costs were reasonably accurate.

5. Despite their general accuracy, including the total costs of generation, APS over- or under-stated individual coal, oil, and gas generation costs due to a misclassification of costs among the three types of generation. *(Recommendation #3)*

6. Liberty's detail testing of August 2005 PSA data found the supporting information to be well documented and reasonably consistent with the values reported.

7. Liberty's detail review of the non-confidential PSA Over/Under values found them to be accurate, but they should be more transparently supported. *(Recommendation #4)*

8. A review of APS handling of supplemental fuel charges and refunds indicates that supplemental charges and refunds have been accounted for in the PSA when applicable; the accounting methods are not consistent for purposes of recording refunds, but the inconsistency has not had a material impact on the PSA. *(Recommendation #5)*

Recommendations:

1. Conduct periodic internal audits of the PSA filings to verify the soundness, completeness, and accuracy of the activities that produce them, with the first such audit to be conducted as part of the next audit plan. (*Conclusion #2; Priority 2*)

2. Develop a written policy and procedure for the preparation of the confidential PSA filings. (*Conclusion #3; Priority 2*)

3. Correct PSA reporting methods to assure more accurate classification and reporting of coal, oil, and gas generation information. *(Conclusion #5; Priority 2)*

4. Revise the PSA confidential filing format to provide a sufficient level of detail to support the calculation of the components contained within PSA non-confidential filings. *(Conclusion #7; Priority 1)*

5. Closely review and monitor adjustments to fuel costs to assure that supplemental charges and refunds appropriately consider the impact on inventory values and fuel expenses for financial reporting purposes. *(Conclusion #8; Priority 2)*

II. Organization, Staffing and Controls

A. Scope

This chapter addresses the following topics related to the goals, strategies, organization, policies and procedures that guide APS fuel and energy procurement and portfolio management:

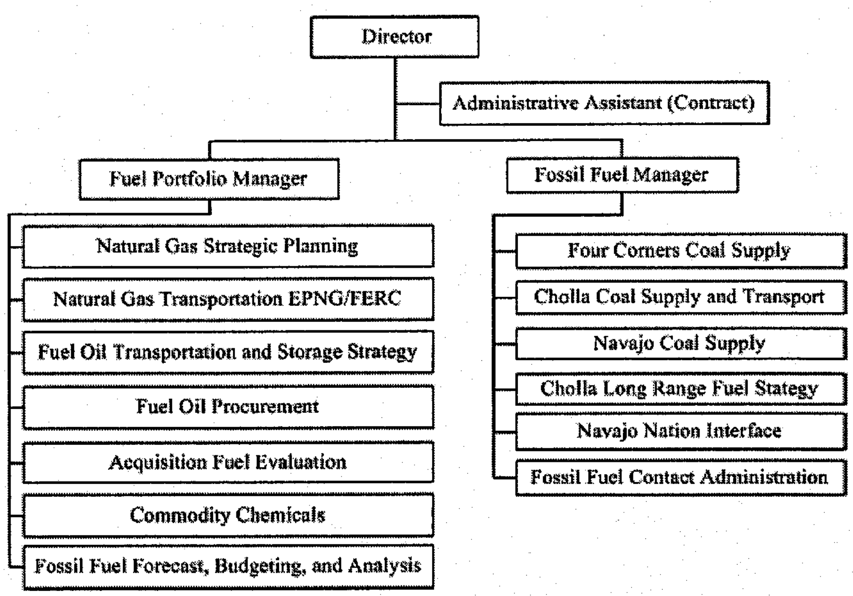
- Organization structure
- Staffing
- Approval authorities
- Goals, strategies, policies and procedures
- Documentation requirements
- Auditing.

B. Findings

1. Fuel Procurement and Management Organization

The Fuel Procurement Group, headed by the Director, Fuel Procurement, secures fuel for power generation at APS. The Fuel Procurement Group reports directly to the Vice President, Fossil Generation, who in turn reports directly to the President and CEO of APS. This group manages all aspects of fossil fuel management, including budgeting and analysis, fuel and transportation procurement, chemical procurement, waste product management, and contract administration. The group, however, does not procure natural gas. While it does secure the transportation services for natural gas, APS Marketing and Trading procures the natural gas commodity. The following chart depicts the organizational structure and the functions for which each Manager is responsible.

Figure II.1 APS Fuel Procurement Group Organization



The Fuel Procurement Group contains three senior personnel:

- The Director
- Two managers reporting to the Director: the Fossil Fuel Manager and the Fuel Portfolio Manager
- Three individuals reporting to the Fossil Fuel Manager
- Four individuals reporting to the Fuel Portfolio Manager.

The Director, Fuel Procurement has responsibility for meeting fossil generation requirements at lowest possible cost by directing the:

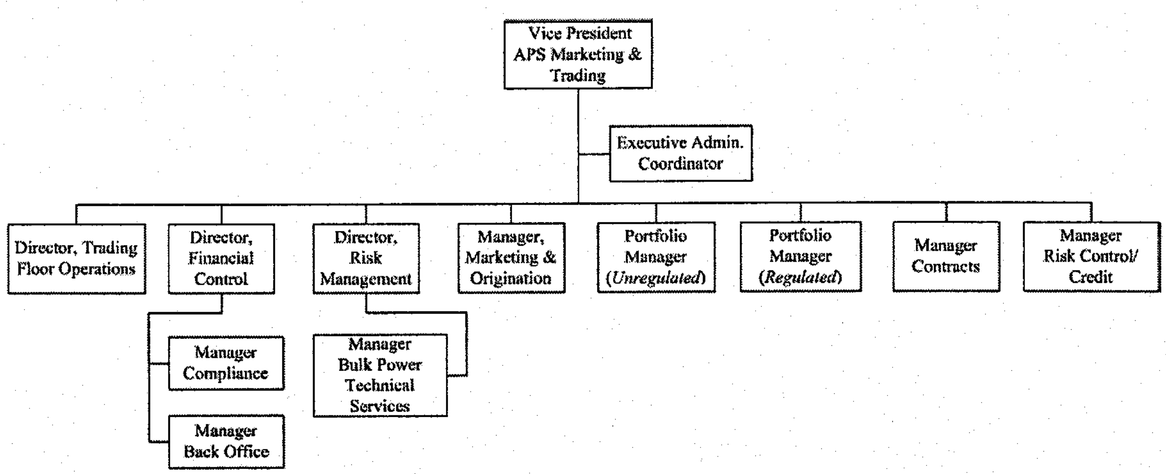
- Design, development, and implementation of comprehensive fuel strategies
- Acquisition of fuels, water, and lime
- Associated contract administration
- Development, evaluation, and implementation of cost and performance metrics.

The Fossil Fuel Procurement Manager is responsible for implementing the fossil-fuel strategic plan, and for negotiation, procurement, and administration of all fossil contracts, including the arrangement of coal-transportation requirements. The Fuel Portfolio Manager is responsible for managing design, development, and implementation of comprehensive corporate strategies to optimize use of the Generation Business Unit asset portfolio. He is responsible for acquisition of natural gas transportation services, fuel oil procurement, transportation and storage, commodity chemicals, and fossil fuel forecasting, budgeting and analysis.

2. Electric Power and Natural Gas Procurement and Trading Organization

The Vice President, APS M&T heads the department, and reports to APS's CFO. Two directors and eight managers report to this Vice President. The following figure shows this organization.

Figure II.2 APS M&T Organization



The APS Marketing & Trading ("APS M&T") Department is responsible for:

- Economic dispatch of generating units on the APS system

- Procurement of wholesale purchased power and natural gas for APS native load needs
- Marketing of surplus APS generation and natural gas
- Risk management and control activities for electric power and natural gas transactions.
- Performance of certain financial control operations that support trading and hedging activities (often referred to as the "mid-office" and "back-office" activities).

The APS M&T's Portfolio Manager (Regulated) has responsibility for:

- Procuring term supplies of wholesale purchased power for the utility
- Procuring natural gas for the utility
- Marketing surplus APS generation and natural gas
- Using all available trading and hedging tools, such as futures, options, swaps, and derivatives to carry out the APS hedging program.

The Portfolio Manager (Regulated) works closely with M&T's Director of Risk Management to determine physical and financial risk exposures, and to manage these risks.

The Director, Trading Floor Operations within M&T is responsible for real time electricity and natural gas trading, resource commitment, and bulk power scheduling. He coordinates all electricity and natural procurements having durations up to 30 days, including portfolio integrity, risk management and business development. He maintains close relationships with the Portfolio Manager, the Director, Fuel Procurement, and the Generation Group, in order to coordinate market conditions and system needs with fuel contract status and power plant operations.

3. Performance Measurement

An overall APS program for performance management guides measurement of employee performance in Fuel Procurement and in APS M&T. This program includes annual performance evaluations conducted by immediate supervisors of employees. Part of the evaluation process includes establishment for the next year of goals related to measurable objectives for fuel and power procurement management and operations. Reviews conducted at the end of each year between employees and managers affect decisions about salary changes.

The Vice President, Fossil closely monitors the performance of both fuel procurement and power generation activities through a number of regular meetings and reports. He conducts monthly, individual meetings with each person who reports directly to him. In addition, he meets every two weeks with representatives from each of the power generating stations. The Vice President's direct reports include the following twelve persons:

- Director, Fossil Fuel Procurement
- Director, Generation Engineering
- Director, New Generation
- Plant Managers (there are 8 of them)
- Manager, Technical Services.

The Vice President Fossil regularly monitors a number of monthly reports addressing fuel and power generation; they include:

- Fuel inventory and deliveries – actual compared to planned
- Fuel expense by station – actual versus budget and variances
- Fuel variance explanations
- Estimated coal and oil prices for power plant dispatch (which the Vice President approves)
- Detailed fuel variance analysis by station
- Heat rate target versus actual for the month and for 12 months for each generating unit
- Non-commodity and secondary fuel expenses.

The President and CEO of APS follows a similar pattern of meetings and reports to monitor the performance of fuel and power generation activities. He meets monthly in individual sessions with each individual reporting directly to him. He also holds monthly staff meetings with all officers. He monitors generating unit availability, gas and energy prices, and hedge positions on a daily basis. He regularly monitors fuel, power and station activities compared to budgeted performance.

The President and CEO cited recent, major activities related to assessing, negotiating, and executing new coal supply agreements for the Cholla Generating Station as an example of the types of special, non-recurring issues typical of those that he personally follows closely. He cited as another example the accompanying new rail transportation agreements, which APS found necessary to review because mining operations at the McKinley Mine wind down earlier than originally anticipated. He reviewed the final agreements prior to their execution, but they were signed by the appropriate Company official as specified by the corporate policy addressing authorization limits.

The President and CEO cited a number of the types of issues about which he advised the Board of Directors, mentioning plans, progress, and the final contract status of the new coal supply, and associated rail transportation, to the Cholla Station. Liberty found documentation in Board of Director minutes confirming review and discussion of these activities, as the change in coal supply for the Cholla Station progressed from initial plans to final coal and rail contracts.

4. Training

APS does not use a formalized training program or training manual for employees in the fuel and power procurement function. APS does, however, operate a number of specific ongoing training programs, and conducts a variety of less formal cross-training activities:

- All employees must take standard corporate safety training classes that include Emergency Evacuation, Hazard Communication and Defensive Driving
- All employees receive Ethics and Standards of Business training provided by the company; this online training concerns the Company Ethics Policy and Standards of Business Practices, and is explained in detail in the corporate booklet entitled *Do The Right Thing*

- APS M&T personnel have been participating since December 2005 in live training sessions on the *Market Behavior Rules* of the Federal Energy Regulatory Commission ("FERC"); the sessions will continue through March 2006
- Other training programs for generating station personnel address various skills, specific power plant operational areas, simulator training and safety-related training.

Fuel Procurement personnel must take specific courses addressing ACC and FERC Code-of-Conduct requirements. This training provides a brief description and explanation of the actual codes and the Company policies and procedures to ensure that the employees of the PWCC family of companies comply with the requirements of the two commissions.

Fuel Procurement personnel receive encouragement to attend selected seminars or training courses related to their specific areas of fuel purchasing, transportation, or management. The department also routinely works on cross training, and has incorporated requirements into performance evaluations. Examples include:

- The Director, Fuel Procurement recently served on a temporary, one-year job rotation assignment with APS M&T operations on the trading floor
- The Fossil Fuel Manager served on temporary assignment to the Ocotillo Station last summer
- The Director and the Managers who report to him have handled the chemical procurement function.

APS uses an eight-step, organized succession management process to develop a succession plan for positions within the Company. These eight steps are:

- Position profile creation
- Initial identification of candidates
- Candidate profiles creation
- Calibration review
- Position profiles and candidate profiles entry into succession management data base
- Development plan discussion
- Periodic reviews
- Reports.

Such a plan exists for the Director, Fuel Procurement position. APS has currently identified three candidates for this position. These individuals have been rated against the profile created for this position and the necessary developmental needs and plans for each of these individuals have been documented.

5. Job Descriptions

Job descriptions for employees in the fuel and power procurement functions are current, and adequately reflect the responsibilities of the positions for which they have been written. These job descriptions provide the starting point for defining job responsibilities against which individual performance is measured in the performance evaluation process.

6. Staffing

The vice presidents, directors, and managers in the fuel and power procurement functions have adequate background and experience for the positions that they occupy. The Director, Fuel Procurement has been with APS for 25 years, and has been in the fuels organization for over 9 years. The Fossil Fuel Manager has been with APS for 21 years, and has been in the fuels organization for approximately 10 years. The Fuel Portfolio Manager has been with APS for 16 years, and has been in the fuels organization for 7 years. The Vice President, Fossil Generation, to which the Director reports, has been with APS for 42 years, having held a number of positions of increasing responsibility related to management and operations of APS generating stations.

The Vice President, APS Marketing & Trading has been with APS for 26 years. He progressed through a variety of power plant positions, became an electrical engineer while working at APS, and was named the Director of Bulk Power Marketing and Resource Operations in 1996.

The Director, Trading Floor Operations has been with APS for 28 years, and has been in the Bulk Power Marketing Department for 10 years. The Portfolio Manager has been with APS for 18 years, and has been in APS fuel and gas trading areas for 14 years. He has served as APS's Director of Generation Fuel Procurement, and has held his current position for two years.

The level of background and experience for senior employees in both fuel and power procurement positions typifies that of lower levels in the organizations as well. The relevant APS organizations are staffed by mature, experienced individuals. This strength shows that a long-range emphasis on candidate identification and personal development has served to ensure continuation of the appropriate level of experience.

7. Approval Authorities

Several corporate policies related to decision-making control the approval of procurement activities within the fuel and power procurement organizations. Corporate Policy #51 addresses delegation of authority. It provides for delegation of authority as necessary to accommodate the business needs of the Company, while maintaining adequate control. It specifies that the Controller oversee the delegation of authority and the authorization levels necessary to execute various procurement and work authorizations.

APS has supported this delegation of authority policy with a formal system of controls within the MLIS computer system. These controls establish commitment levels for each level of management. A *Decision Matrix* includes the name of the employee, and the following designations for which the individual has authority:

- Business Entity
- Account Type
- Document Type
- Authorization Limit.

Liberty's test examination of a number of fuel-supply procurements found that the proper level of management executed the necessary agreement. Liberty also examined the degree of involvement of senior management and the board of directors on major procurement decisions. Liberty found that top executive management and the board, were timely informed of initial plans of action, recommendations for new suppliers, and the associated transportation agreements for a new coal supply to the Cholla Station, which involved a large and important set of procurement actions for the Company.

8. Goals and Strategies

APS groups involved in fuel and energy procurement operate under business plans, or what APS terms "Initiatives." The corporate business plan incorporates specific success indicators or targets (such as production costs in cents/kWh) for the current year and for five years into the future. These success indicators include the following categories:

- Safety
- Reliability & Operations
- Customer Satisfaction
- Growth
- Workforce
- Environment
- Financial Leadership.

The *Generation Business Plan* is similar in nature, and includes its own specific success indicators or goals for the current year: These goals include the categories of:

- Safety
- Reliability and Efficiency
- Production Cost
- Environmental.

The Fuel Procurement organization develops initiatives for each year. The 2005 initiatives, for example, addressed fuel supply issues for each of the large generating stations, fuel portfolio initiatives, and administrative initiatives. The initiatives for 2005 for the Cholla Station included several specific actions related to the need to develop new coal supply and transportation agreements, recognizing the wind-down of coal mining operations at the McKinley mine, which has supplied this station for many years.

Initiatives for 2006 fall into the same overall action categories as the 2005 initiatives, but included new station-specific and new fuel portfolio items. One of the important new items identified for the Four Corners Station was the longer-term need to assess optimum ash disposal methods. The BHP ash hauling costs passed on to APS will likely increase significantly in a few years, because it will become necessary to use a new ash disposal area much farther from the station.

9. Policies and Procedures

APS does not have procedures for procurement of coal. Throughout the operation of its two major coal-fired stations, Cholla and Four Corners, the Company has had "life of plant" coal supply agreements. The narrow scope of buying requirements (although the volume is large) has led APS to consider coal procurement procedures to be unnecessary. APS also does not have procedures for coal contract management and administration, but it does have a set of flow charts addressing some required activities for Cholla and Four Corners. These flow charts, however, do not include many significant coal contract management and administration processes.

For example, the Cholla charts contain no indication of timing of any of the process steps. Further, APS has not addressed any steps in the processes for coal sampling, analysis, or data handling. The documentation also fails to address important elements in the creation of the Cholla *Coal Receiving Report*:

- Whether and how station personnel should obtain independent data on the weight of coal
- What specific scales should be used
- What process should be followed to secure coal-weight data from the scales (automatically printed or written down by someone)
- How weight data gets to the proper place for further steps in receiving report creation.

The Cholla charts also do not make a clear conversion from tons to BTU. Utilities buying coal seek energy, or heat content, not just tons. Liberty is accustomed to observing clarity in how a utility converts to, reports, and analyzes BTU content.

APS M&T uses a number of policies and procedures to manage natural gas and purchased power procurement for system native load requirements. An overall APS hedge policy provides an overview of the philosophy, strategy development, target setting, methods, and controls supporting the management of the electric power and natural gas commodity risks associated with load-serving obligations. A more detailed *System Hedge Plan* provides specific actions, targets, plans, and metrics. The document sets forth the main elements of the hedge plan in terms of target hedge levels by specified dates, the elements of current system risk, and the overall term of hedges. APS also operates under detailed corporate *Energy Risk Management Guidelines*. This comprehensive document contains an extensive discussion of energy risk-management philosophy, objectives, processes, and controls.

APS also has documented methods for handling the affiliate aspects of energy and fuel procurement. Its Cost Allocation Manual ("CAM") bears on fuel and energy management. APS has developed procedures that address cost allocations, and are contained in *ACC Code of Conduct Policy No. 1* of the *Policies and Procedures*. This eight-page set of procedures, entitled *Affiliate Accounting Policies*, provides overall guidelines and standards to ensure compliance with regulatory requirements related to competitive electric affiliate relationships. This document does not contain detailed cost allocation procedures, but instead provides overall policy guidance on accounting for affiliate transactions involving APS.

APS code-of-conduct procedures reside in several documents, starting with Company policies and procedures that implement the ACC Decision No. 62416. These procedures contain a set of nine specific policies that relate specifically to dealings with affiliates:

- Policy 1: Affiliate Accounting Policies
- Policy 2: Access to Information
- Policy 3: Compliance
- Policy 4: Contracting for Personnel Services Between APS and Its Competitive Retail Electric Affiliates
- Policy 5: ESP Contacts and Requests for Service
- Policy 6: Joint Promotion, Sales, and Advertising with a Competitive Retail Electric Affiliate
- Policy 7: Physical Separation of Entities
- Policy 8: Shared Officers and Directors
- Policy 9: Training Policy.

The Company's *Energy Risk Management Guidelines* ("ERMG") also set standards for the ethical conduct of employees in fuel and power procurement functions. APS updates at least annually these detailed procedures outlining compliance and enforcement requirements. The ERMG also incorporates the FERC's *Market Behavior* rules, which form part of APS's FERC-approved *Market Based Rate Tariff*, and provide descriptions of risk policies and related procedures. The APS training program addresses employee understanding of and compliance with code-of-conduct procedures.

10. Documentation Requirements

Effective fuel management depends upon two general categories of documentation:

- *Procurement*: information documenting the scope and nature of activities to secure fuel, transportation, storage, and related requirements. Typically, this data reflects whether fuel was procured through an organized process, and through a competitive bidding process that produces delivery to the generating stations at costs (consistent with quality and reliability objectives) that will produce the lowest cost of electricity at the bus-bar.
- *Administration*: fuel-delivery data that must be monitored on an ongoing basis to manage effectively the existing fuel contracts. Information in this category includes fuel quantity, quality and schedule data. Associated with this information will be the concurrent power plant performance data that reflects the efficiency of power generation when the fuels currently being procured and delivered are burned for the generation of electricity.

APS has occupied for many years an uncommon position for a coal-burning utility. The Cholla and the Four Corners Stations have operated under long-term coal contracts referred to as "life-of-plant" contracts. This position has made APS a much less frequent market participant (at least for large-volume purchases or transportation) than is typical of many other utilities. Four Corners is essentially a mine-mouth plant. An adjacent mine delivers its coal from the mine via conveyor belt. APS anticipates that that this coal supply will last well into the future. Thus, there has not been need or significant opportunity to procure large, new supplies of coal for Four Corners. Without this need, there has been a corresponding lack of need for procurement documentation.

Similarly, APS originally had a very long-term arrangement for the supply of coal to Cholla from the McKinley Mine, located only 117 miles away. The Cholla Station was designed to burn coal from this mine. A difference from Four Corners, however, is that supplies from the McKinley Mine are now projected not to last as long as originally anticipated. APS therefore began in 2004 the process of soliciting new coal supply sources for Cholla.

The recent emergence of a need for alternate supply at Cholla brought new challenges to APS. The Company did not develop or use written procedures for that procurement. APS, however, did follow a structured, disciplined process for procurement of new Cholla supply. This process produced substantial documentation, which Liberty examined. The *Fuel and Purchased Power Contracts* chapter of this report provides a discussion this procurement's decision process. Liberty's review of the documentation showed:

- Issuance of requests for proposals to a substantial number of potential coal suppliers
- Economic analysis of incoming bids
- Consideration of the impacts of the potential new coal supplies on the Cholla Station
- Coordination of coal price information with requests for new rail rates from the railroad
- Timely information to management about the status of the procurement process.

Documentation for fuel oil and natural gas purchases reflects the very different procurement processes that characterize the purchasing of those fuels. In both cases, common industry practice is to establish formal relationships with a large number of suppliers, and then to place orders for specific quantities in response to established suppliers' offers of supply. An order for gas might be for an amount sufficient to operate a generating unit for a month, or for a few hours. An order for fuel oil might be for one load of a tanker truck.

In this market environment, industry practice is to enter standard form contracts with suppliers, and then to place orders for discrete quantities under those contracts. The form contracts cover ordering procedures, fuel quality, and commercial issues, such as warranties and billing and payment terms. Orders often take place through telephone calls, followed by purchase orders, in the case of fuel oil. For gas, an APS gas trader selects offers from an electronic trading platform, or by telephone contact with offerors. In the case of gas, the supplier sends confirmations by via facsimile or e-mail to confirm the order. APS checks those confirmations against prices and quantities entered into the Company's transaction-tracking system by APS's trader.

The second category of important fuel management documentation addresses the implementation and administration of fuel contracts that result from the procurement process. The APS Fuel Procurement organization monitors the activities related to management of existing fuel contracts through a number of documents specifically designed for this purpose. These documents form the basis of information routed to senior management of APS on a monthly basis. Primary documents used regularly for management of fuel contracts include the following:

- *Daily Coal Shipments*: This information, which coal-handling personnel at the stations provide, serves as a primary tool to ensure vendor compliance with quantity, quality and schedule requirements. It contains coal quality data, coal weight information, rail shipment designations, and summary monthly information.

- *Monthly Cholla Coal Inventory*: This information lists actual and target inventory information for each of the various coal types maintained in Cholla inventory. Information arrives electronically from the station; Fuel Procurement personnel maintain it on spreadsheets as a tool in contract management.
- *Cholla Coal Receipts*: This information details the monthly coal receipts by vendor, and comprises the tool for measurement of contract compliance.
- *Monthly Coal Fuel Variance Analysis*: APS Fuel Procurement personnel prepare this report for each fuel type; it provides annual year-to-date fuel costs and budgets, along with details of all of the components of the costs for each station. For example, the seven components of the Cholla costs, listed in terms of cents/kWh, comprise:
    - Regular sulfur coal
    - Low sulfur coal
    - Accruals
    - Inventory adjustments
    - Secondary fuels
    - Heat rate efficiency/Fuel handling
    - Other variances.
- *Monthly Total Coal Plant Fuel Costs*: This data, presented in both tabular and graphical form, provides actual and budget fuel cost information, by month, for all plants and for each station individually, with data listed in both total dollars and cents/kWh.
- *Monthly Fuel Variance Analysis, Gas/Oil*: This report is similar to the report for coal.
- *Monthly PNW Gas Transportation*: This data provides monthly and year-to-date gas transportation information.
- *Daily PNW Gas Burns for the Month*: This data provides daily burns of gas, in MMBtu, for the PNW system, in both tabular and graphical format.
- *Monthly Oil Inventory*: This report lists the diesel and residual fuel inventories at each station that uses these fuels. The data includes fuel receipt and burn information required to determine inventories.

11. Auditing

The internal auditing function within APS Audit Services has conducted internal audits of fuel procurement, power procurement and price-risk management. In the last three years ending in late 2005, the group has conducted 25 such audits. Each audit report includes:

- An executive summary addressing:
    - Objective
    - Conclusion
    - Recognized Strengths
    - Improvement Opportunities & Management Response
    - Status
- A detailed report describing:
    - Background

- Work Performed
- Scope
- Issue
- Management Response
- Observation.

Audit Services defines an audit *issue* as an identified deficiency with respect to regulatory requirements, corporate policies and procedures, or EHS Management Practices reviewed during an audit. Audit Services requires a *Management Response* to all *issues.* Observations are behaviors/practices recognized by the auditor(s) during the audit. Observations are made to increase the overall effectiveness of the programs and to highlight good management practices. Audit Services does not generally require a management response for observations.

A number of the internal audits addressed BHP coal-contract price-escalation issues. These audits have [redacted] Their conduct has strengthened the coal-contract administration process. Their objectives have been to determine whether:

- BHP properly escalated the price of Four Corners Power Plant coal
- Appropriate contract and administrative controls were in place to ensure compliance with the fuel agreement.

Another internal audit addressed coal accounting at the Cholla Station. It examined the processes and procedures for handling coal and calculating fuel expense and coal inventory at the station. This audit addressed the issue of [redacted] Fuel Procurement personnel informed Liberty that [redacted] This same audit also addressed coal inventory adjustments. It [redacted]

Several audits addressed natural gas issues. Two addressed price index reporting, after the FERC established new requirements for this activity in 2003. Additionally, an industry-standards group issued a "Best Practices" guide for this activity. The auditors concluded that APS's policies and procedures in this area [redacted].

Liberty's examination of these internal audits across the past three years demonstrated attention to important components of the fuel and power procurement operations and risk management. The audits took place with acceptable frequency, addressed issues adequately, did [redacted], identified [redacted], and produced timely and appropriate responses from APS management. Liberty understands that Audit Services intends to continue to conduct them on a regular basis.

12. Board of Director General Oversight of Fuels and Energy

The parent and APS boards have common membership. Their meetings are technically distinct, but often held on the same day. The parent classifies nine of its twelve directors as independent under New York Stock Exchange ("NYSE") and *Director Independence Standards* adopted by the parent board. The board has the following standing committees:

- Audit: assists the Board in monitoring financial statement integrity, independent auditor qualifications and independence, performance of the internal audit function and independent auditors, and compliance with legal and regulatory requirements. (Met six times in 2004 and six times in 2005).
- Human Resources: reviews compensation strategy; approves compensation and benefits policies, approves CEO compensation goals and objectives, assesses CEO performance, sets CEO compensation, recommends persons to the full Board for election or appointment as officers, and makes director compensation recommendations to the full Board. (Met three times in 2004 and five times in 2005).
- Finance and Operating: reviews historical and projected financial performance, follows issues affecting financial condition, recommends approval of short-term investments and borrowing guidelines, reviews financing plan, recommends approval of issuance and redemption of securities, credit facilities, and other types of credit support, recommends approval of the general parameters applicable to long-term debt and equity security issuance, and recommends dividend and other distribution actions to the Board. (Met four times in 2004 and four times in 2005).
- Corporate Governance: develops corporate governance policies, practices, and guidelines, recommends to the full Board criteria for selecting new directors, identifies and evaluates individuals for Board membership, recommends director nominees to the Board, and recommends committee assignments to the Board. (Met four times in 2004).

The following table summarizes the assignments of the current members of the parent board.

Figure II.3 Board of Directors and Committee Membership

				Committees				Subsidiary Boards				
Director	Independent	Tenure	Age	Audit	HR	Corp. Gove	Fin. & Ops	APS	PWEC	APSES	SunCor	El Dorado
Basha	Y	1999	68	M	M	M		X	X			
Davis	N	2001	59				M	X				
Gallagher	Y	1999	61				C	X	X		X	X
Grant	Y	1985	67	M	M	M		X	X		X	
Herberger	Y	1992	63		C	M	M	X	X			X
Hesse	Y	1991	63	C		M	M	X	X			
Jamieson	Y	1991	62	M	M	M		X	X			
Lopez	Y	1995	60	M	M	M		X	X		X	
Munro	Y	2000	57	M		C	M	X	X			
Nordstrom	Y	2000	56	M		M	M	X	X			
Post	N	1997	55				M	X	X	X	X	X
Stewart	N	2001	62				M	X	X	X		

The following summaries from recent proxy statements describe the directors' backgrounds:

- Basha, Edward N. Jr.: Chairman of the Board of Bashas' supermarket chain since 1968 and an Arizona civic leader.
- Davis, Jack E.: Pinnacle West COO and President and APS President and CEO; formerly in various APS executive positions (including generation and transmission) since 1993.
- Gallagher, Michael L.: Chairman Emeritus of the Phoenix law firm of Gallagher & Kennedy, P.A.
- Grant, Pamela: Civic leader, former president and CEO of Goldwater's Department Stores, and former president of TableScapes, Inc. (party supply rentals)
- Herberger, Roy A, Jr.: Former President and now President Emeritus of Thunderbird, The Garvin School of International Management
- Hesse, Martha: Former President of Hesse Gas Company former Sr. VP of First Chicago Corporation (financial services), and former Chairman of the Federal Energy Regulatory Commission
- Jamieson, William S. Jr.: President of Micah Institute of Asheville, North Carolina and former President for the Institute of Servant Leadership
- Lopez, Humberto S.: President of Tucson-based HSL Properties, Inc. (real estate development and investment)
- Munro, Kathryn L.: Principal and former Chairman of BridgeWest, LLC (investment company) former CEO of Bank of America's Southwest Banking Group
- Nordstrom, Bruce J.: CPA and President of Nordstrom and Associates, PC, Flagstaff, AZ
- Post, William J.: Pinnacle West Chairman and CEO, and Chairman of subsidiaries, APS, PWEC, APSES, SunCor, and El Dorado; in executive positions at APS since 1982.
- Stewart, William L.: Retired (2003) CEO of affiliate PWEC and former President, Generation, of APS

The board met nine times during 2004 and nine times during 2005. Senior APS executive management routinely reported the following information during 2005 and early 2006 meetings:

- Year-to-date Generation and APS M&T performance
- Comparisons of actual versus budgeted performance for coal, nuclear, capacity, and availability.

The meeting minutes also disclose that management discussed the following types of subjects at various points during the year:

- Update on a proposed pipeline project
- Status of rate proceedings and fuel/energy cost recovery
- RFPs for securing energy from the marketplace
- Status of negotiations on new Cholla coal and rail transportation agreements and options
- Review of gas and oil market prices with outside auditor
- Sale of natural gas storage development project
- Summary of generation shortfalls, Arizona merchant generation, renewables, new generation technologies, and overall generation options

- Review of recent rate changes for McKinley mine coal transportation
- Fuel and purchased power hedging, comparison of hedged prices with market prices, and forecasts for oil and natural gas demand growth.

13. Board Risk Management Role

PWCC's board of directors has the responsibility for approving the overall risk profile and for establishing an infrastructure to support it. Specifically, its duties include:

- Approving the risk policy
- Approving overall business strategies for risk management and control
- Reviewing those strategies periodically
- Approving overall risk limits.

The PWCC Energy Risk Management Guidelines state that the board of directors has delegated risk management and monitoring responsibility to the PWCC Energy Risk Management Committee ("ERMC"), which consists of:

- PWCC and APS CFO and Executive Vice President (Committee Chair)
- PWCC Vice President and General Counsel
- APS Vice President – Planning
- PWCC Audit Services Director
- APS Directory of Energy Risk Management
- APS Vice President and Controller
- APS Director of Tax Services
- APS M&T Vice President
- APS Executive Vice President of Generation
- APS Vice President and Treasurer.

The Risk Management Guidelines assign specific responsibilities to the EMRC:

Monthly

- Review the PWCC risk position
- Oversee Energy Risk Management Group ("ERMG") enforcement activities
- Review and approve summaries of limit violations
- Take appropriate corrective actions to respond to violations
- Review and approve the addition of products not on the Approved Products List
- Review aggregate and individual credit exposure information

Annual

- Determine risk capital to be allocated to APS M&T and APSES
- Establish and maintain risk tolerance limits
- Present reports to the PWCC board of director's Finance and Operating Committee on significant exposures and risks

- Present reports to the PWCC board of director's Audit Committee on APS M&T and APSES controls and systems

As Needed

- Approve counterparty credit limit structures
- Approve portfolio-level trading limits
- Approve new products and trading instruments
- Monitor risk management staffing adequacy and clarity of authority and responsibility for risk management
- Approve changes to the Risk Management Guidelines
- Review non-standard transactions and hedging plans.

C. Conclusions

1. Personnel in the fuel and power procurement have solid analytical skills and sound experience appropriate to meeting objectives and responsibilities.

Fuel and power procurement personnel have sufficient experience in the essential activities of fuel planning, procurement, and management. Liberty's review of work products created within the department during this audit indicated that the capabilities of all of the individuals in the fuel and power procurement organizations are strong and consistently applied. Interviews with personnel verified the existence of the proper skills to perform the tasks assigned. Liberty's observations about the capabilities of APS personnel also demonstrated the ability to grow into larger roles, if development is appropriately supported.

2. Job descriptions for personnel in fuel and power procurement are current, and adequately address current responsibilities.

The job descriptions related to the activities performed by employees in the fuel and power procurement functions are current, and reflect the present responsibilities of positions to which they apply. APS appropriately uses job descriptions as the frame of reference for the assessment of job responsibility performance in personnel evaluations.

3. Communication within and among the fuel and power procurement organizations and upper levels of management is satisfactory.

Personnel within the fuel and power procurement organizations displayed a good understanding of the overall mission of their departments, of current activities and challenges, and of key strategic and tactical issues within the organization. Common understandings reflect good communication within the organization and management attention to the importance of involving all personnel in the activities of the organization.

Communication with upper levels of management takes place effectively through a regular process of staff meetings and formal written reports prepared for the Vice President, Fossil, as well as the President and CEO of APS.

4. The fuel and power procurement organizations have a satisfactory program for training and cross training of individuals within their departments.

The fuel and purchased power organizations do not have formal training or cross-training programs documented through a manual or plan. These organizations have taken a less formal, but effective approach to training and cross training. They recognize training as an ongoing process, and accomplish it effectively through a combination of on-the-job cross training, various industry seminars, conferences, and internal programs.

APS maintains thorough succession plans for senior positions within the organization; they specifically identify individuals capable of filling senior positions.

5. APS maintains an appropriate decision matrix, or chart of approval authorities.

APS maintains several procedures related to decision-making and delegation of authority, and an appropriate decision matrix, or chart of approval authorities, that specifies the magnitude of commitments that can be made by various levels of management.

6. The program for employee training and compliance monitoring under the Code of Conduct is satisfactory.

APS has developed and communicated adequate procedures governing ethical behavior of employees. APS employees receive annual training on these Standards of Conduct, and attendees sign a statement certifying that they have received this training,

7. The fuel and power procurement organizations have satisfactory procedures for many of the specific functional areas within these organizations, but Fuel Procurement does not have sufficient procedures for fuel contract management and administration. (*Recommendation #1*)

A number of appropriate guidance documents and procedures address the fuel and power procurement organizations. The documentation starts with business plans and initiatives for each year. APS has detailed procedures for dealing with affiliates and code of conduct guidelines. The *System Hedge Plan* and suitably detailed and comprehensive *Energy Risk Management Guidelines* address natural gas and power procurement.

APS follows ASTM procedures in its weighing, sampling and analysis of coal, and in calibration of its coal scales. However, in the area of coal contract management and administration, the Fuel Procurement organization operates only under an incomplete set of flow charts.

8. Documentation of fuel and power procurement and supply management activities is satisfactory.

The business plans and initiatives are central to overall documentation of APS strategies and plans for fuel and power procurement and management. They are well prepared, comprehensive, and available to the right personnel. They contain sufficient detail to provide meaningful documentation of strategies and plans. The fuel and power procurement organizations also use a number of other reports and records to manage the fuel supply process and include appropriate reports necessary to monitor and manage supplier contract compliance and the essential fuel needs of the utility. Upper levels of management are also kept up to date on fuel and power procurement activities through regular weekly and monthly reports.

APS's purchase-order process for fuel oil and its transaction-confirmation process for natural gas are typical for purchases of these fuels. These processes include adequate documentation creation and maintenance, and documentation retrieval ability.

9. The APS Audit Services group conducts regular and appropriate internal audits of fuel and power procurement functions.

APS Audit Services has actively conducted internal audits of fuel procurement, power procurement, and price-risk management. In the last three years ending in late 2005, 25 specific audits have been conducted. Audit Services did [redacted]

10. The Company's procedures for accepting offers of gas supply are not sufficiently formal. *(Recommendation #2)*

The Company buys most of its gas monthly during the week prior to when deliveries would begin. Gas is bought in two ways: (1) accepting pre-approved suppliers' offers posted on an electronic trading platform, and (2) telephone contacts with suppliers. The APS staff person in charge of this activity estimates that about 75 percent of the gas is bought electronically, with the rest bought over the phone.

The parties set the prices to be paid for the gas when the supply offers are accepted. The Portfolio Manager (Regulated), a gas futures trader, and the physical gas trader generally confer prior to accepting each offer. The Portfolio Manager (Regulated) reported that he spot-checks the prices that APS pays against other offers and against price-reporting services.

Liberty's did not observe sufficient formality in the process for overseeing these transactions. At current price levels, this process produces expenditures of $30 to $40 million per month. Expenditures of that magnitude warrant greater structure in assuring that price determination and acceptance always occur as intended.

11. Senior executive management has routinely provided to the board of directors substantial information about fuel, energy, and plant operations performance.

Management provided baseline operating and budget variance information to the board. In addition, at various times during the past year, management advised the board about important milestone events, including major new contracts, coal transportation issues, development of alternative natural gas transportation sources, hedging effectiveness, and cost deferrals.

12. Available summaries of the board members' backgrounds show sufficient experience in matters relevant to utility fuel and energy management; however, Liberty was not able to determine through interviews with them what specific knowledge and experience they bring to bear or what values, criteria, performance indicators, and critical decision/judgment points they apply. *(Recommendation #3)*

The board on paper demonstrates a sound blend of experience level, industry knowledge, relevance to fuel and energy matters, local knowledge, and executive and other leadership ability. The only source Liberty had for confirming the details of that experience and its effective application in overseeing APS fuel and energy management, however, were the board minutes and the impressions of senior management about what the board does.

Liberty ultimately gained sufficient information to conclude that there was no failure of information flow to the board. APS offered access to board minutes and the views of senior executives on what role the directors play in fuel and energy matters and on how they exercise that role. Directors received sufficient regular reporting on fuel and energy matters. It would have been better to discuss with the directors in person what information they consider important and how they use it to oversee this important area of operations. Speaking directly with directors has formed an important process in reviewing how they meet public service responsibilities in Liberty's prior engagements.

Liberty has no reason to believe that there is a gap in senior oversight of fuel and energy matters, but could not corroborate that conclusion through direct discussion with directors. There is not a substantial reason for concern about costs. However, board performance can sometimes form a very important element of a public service commission's examination of utility management and operations. Liberty believes that there should be a clear recognition by APS that the Commission's interests may warrant direct communication with directors in the future.

13. The board's risk management role as defined in written policies and procedures is sound and the risk management program produces effective performance and status reports.

Liberty found the PWCC program generally to be a strong one, and specifically that it meets the needs of APS. If carried out as described, the board's role in that program is appropriate. However, board and board committee minutes do not communicate much that leads to understanding specifically how members use information they get, and make decisions and judgments that are important. The minutes are not out of the range one would expect at a company like PWCC or APS. Minutes, however, generally do not provide a particularly good source for securing much more than a listing of subjects addressed, management representatives who discussed them, and formal votes taken.

D. Recommendations

1. Develop a complete set of procedures related to the management and administration of coal contracts. (*Conclusion #7*)

The Fuel Procurement organization should develop procedures that detail the steps associated with management and administration of its coal contracts. Such procedures are an important tool to document the current institutional memory of how these activities are performed, especially in view of the aging nature of the workforce and the need to capture the lessons learned from the many years of experience that individuals have with fuel management processes.

2. Audit and revise procedures for acceptance of offers for gas supply. *(Conclusion #10)*

APS uses a comparatively unstructured process to make commitments resulting in very large expenditures. Audit Services should review the effectiveness of and the controls associated with the process, and work with APS M&T to revise procedures as necessary.

3. Secure an understanding with APS that Commission auditing includes access to members of the board of directors. *(Conclusion #12)*

Liberty did gain an understanding about what information the board got and about what senior management thinks the board does with that information. Liberty did not see any gaps in that information, nor did Liberty develop concern from the perceptions of management about what the board did with the information (assuming those perceptions to be correct). That information and those perceptions are not, however, sufficient to assess board effectiveness, any more than an assessment of the effectiveness of an employee or an organization can be meaningfully assessed by looking only at: (a) information flowing to it from persons reporting to it, and (b) what persons reporting to it think that their superiors do with that information.

APS should agree that future Commission audits may include access to members of the board of directors.

III. Fuel Management

A. Scope

This chapter of Liberty's report addresses the following topics related to APS's management of its fuel supplies:

- Contract administration responsibility
- Receipt inspections
- Information monitored
- Historical supplier performance
- Disputes and backcharges
- Inventory practices
- Ash disposal.

B. Background

1. Contract Administration Responsibility

Responsibility for overall direction of fuel contract administration rests with the Fuel Procurement department's director, who assigns and coordinates these activities to support the department goals. Each of the two managers reporting to the director also has responsibilities related to fuel contract administration. The Generation Fuel Portfolio Manager has administration responsibilities for fuel oil and natural gas transportation contracts. The Fossil Fuel Manager has responsibility for administration of the coal contracts. APS M&T manages natural gas commodity contracts.

Two Supply Chain Managers ("SCMs") and one Materials and Supply Analyst report to the Fossil Fuel Manager. One of the Supply Chain Managers handles coal supply scheduling and monitoring activities for the Four Corners Station. The other handles these functions for the Cholla Station. The Supply Chain Managers have responsibility for ongoing monitoring of delivered coal quality and quantities and for compliance with the other terms and conditions of the contracts. They establish the initial delivery schedules for each coal contract, in order to pace deliveries of the contracts' annual delivery targets. They update those delivery schedules each month for the balance of the year in order to account for deliveries to date and the balance of the annual contract commitments to be met by each coal supplier. They use regularly updated spreadsheets to support the scheduling process.

One of the Supply Chain Managers spends about one week per month at the Four Corners Station, performing coal-contract administration responsibilities. The BHP coal contract is complex, particularly with respect to price adjustments. The contract provides essentially for [redacted] activities that require close monitoring. This Supply Chain Manager serves as the Fuel Procurement Department interface between BHP personnel and the two APS auditors working at the BHP site. Administration of this coal contract requires what amounts to an ongoing audit process that must examine each element of supplier requests for pass-through to APS of [redacted] costs. One of the APS auditors at the BHP site works for APS

Audit Services; the second works for the APS Engineering Department. The latter has an office at the BHP Mine, and has been monitoring BHP costs for APS on a real time basis for approximately ten years.

The Cholla coal supply agreement is not as complex as the BHP contract for Four Corners. The Cholla contract uses a [redacted] pricing mechanism. Consequently, the Supply Chain Manager responsible for Cholla contract administration focuses more on coal scheduling and logistic operations, and communication with the mine and the BNSF, as necessary to keep coal flowing smoothly between the mine and the station. He travels to the Cholla Station regularly, but does not need to spend as much time at the station as does the SCM responsible for Four Corners. Each Supply Chain Manager has almost daily contact with fuel handling personnel at the Four Corners and Cholla stations.

The Materials and Supply Analyst assists each of the two Supply Chain Managers in handling invoices, serving as the interface between the Accounting Department and Fuel Procurement. He performs all reconciliations related to invoicing, and ensures receipt of appropriate input and approval from the two Supply Chain Managers and the Manager of the Department. This Analyst also assists in the preparation of statistical information that reports monthly fuel delivery and budget information.

APS secures data on actual supplier performance from coal receipts that APS coal handlers process at each station. Plant personnel feed the data from these receipts into the APS computer system. The contracts establish the coal quality parameters against which deliveries are measured each month. Monthly weighted averages generally establish the performance measurement bases. Coal-sample analysis information collected within the computer system at the Four Corners Laboratory is uploaded into the APS computer system, and subsequently monitored by the Supply Chain Managers through various computerized reports on coal quality.

2. Receipt Inspections and Information Monitored

<u>Coal Weights</u>
Certified scales measure all weights for coal delivered to the Cholla and Four Corners generating stations, whether it arrives by rail or by conveyor belt. Contract provisions, however, determine whose scales take the weights used for determining compliance with delivery requirements. Certified mine scales take the contract-compliance weights for shipments to the Cholla Station. The primary Cholla suppliers, the McKinley and Lee Ranch mines, use a weigh-bin type of scale. APS also weighs the coal as it is received at the Cholla Station in order to verify the weights provided by the mines. The station's belt scales perform this function, but are not certified. Typically, weigh-bin certified scales are accurate to within 0.2 percent, while belt scales have a lesser accuracy factor of 0.5 percent.

Certified belt scales at the station measure the weights of coal delivered to the Four Corners Station. BHP maintains and certifies these scales, as the contract requires, to ASTM standards. The two belt scales used for this purpose, designated the 2A and 2B Scales, each have full-load capability of 1,200 tons of coal per hour. Calibration of these scales takes place every six months, in the presence of representatives from the scale manufacturer, BHP, APS, and the Navajo Nation. APS has installed its own separate weigh bin system at Four Corners. APS uses that system for scale calibrations. Calibrated weights are used to calibrate the weigh-bin load cells; the State of New Mexico certifies these weights every five years.

In no case does APS feed coal weights electronically into the APS computer system directly from the scales themselves. Some other utilities have processes for automatically transmitting coal weights in the form of electronic signals from scales directly into a computerized fuel management system. Such direct feed avoids duplication in data handling of coal weight information and it reduces a source of possible error in coal weight information. A series of manual steps in coal-weight data entry and transfer creates multiple sources of error or compromise. These manual steps include reading and interpreting electronic data information, entering it by pencil on paper coal-receipt logs, or, alternatively, reading paper printouts from scales and transferring this weight information onto coal receipt logs with pencil and paper.

The mine prepares a "Manifest" or "Bill of Lading" for each train delivering coal to Cholla. This document states the amount of coal loaded into each rail car and the total weight of the train. The BNSF also provides a "switchlist" verifying the cars delivered to the station for each train. Utility Equipment Operators at Cholla record the weight of coal fed to one of Cholla's four operating units, or to one of the plant stockpiles to be reclaimed later. Coal weights are manually recorded in unloading report forms, scale reports are printed, these reports are attached to the train manifest, and they are hand carried each day to the Cholla Accounting Department. There, a station accountant enters this data into spreadsheets that track coal by unit, and by inventory stockpile. Another station accountant then crosschecks the data. The accountant then uses these spreadsheets to key the data into the APS computer system. This process includes multiple handling of the same piece of coal weight data from the time of coal unloading until the data is finally in the APS computer system.

Belt scales weigh Cholla coal at various points, as it proceeds through the station's fuel unloading system. APS then compares the Cholla scale weights with those on the mine's manifest, in order to verify that the proper amount of coal has been received and unloaded. APS investigates any apparent discrepancies. The Cholla Accounting Department manages this weight comparison activity. They tally a running variance between the plant's scales and the supplier's scales, and use this variance as an adjustment factor to determine the quantity of coal burned when coal is reclaimed from inventory from one of Cholla's stockpiles for burning in the operating units.

An October 2003 APS Audit Services internal audit report [redacted]

At the Four Corners Station a representative of APS and the BHP Navajo Coal Company read, every 24 hours, the digital electronic scale display in the coal sample tower building, record the coal weights from both the 2A and 2B belt scales, and sign the "Coal Delivery Log Sheet Daily Report." This multi-part document then gets hand carried to the shift supervisor, the operations manager, the station accounting clerk, and the fuel laboratory. An accounting clerk at the station uses this document to enter daily coal tonnages into the APS computer system.

Liberty's examination of processes used to track coal weight information found routine performance of appropriate comparisons to contract requirements, in order to verify vendor compliance. Liberty also found effective APS communication with vendors on coal-weight related issues.

Coal Samples and Sample Analysis

Personnel at the Cholla and Four Corners generating stations visually inspect all coal received, in order to ensure that it exhibits no contamination from extraneous materials such as wood, metal, rocks, and other miscellaneous debris. APS fuel contracts contain provisions for rejection of coal if such contamination is found. In the last five years, only one Cholla shipment, from a Colorado supplier, had to be rejected.

APS samples all coal delivered to Cholla and Four Corners to verify that the quality of coal delivered falls within contract specifications. As with weights, the contracts specify whose samples must be used for these determinations. Samples taken at the mines by the vendors form the basis for analyses of Cholla coal shipments. Cholla personnel have conducted structured studies to confirm the accuracy of vendor-taken coal samples and analyses. The first study, covering a six-month period, statistically compared: (a) coal-sample analyses from the McKinley mine, (b) APS analyses conducted on a split of the mine sample, (c) a sample taken from the Cholla coal mills, and (d) station emission monitoring data. APS took the emission monitoring data 24 to 30 hours after the mine samples were taken, in order to allow for the normal transportation delay in the flow of coal from the mine to the station. These studies showed a close correlation between samples taken at all locations, and confirmed to the satisfaction of APS that coal samples and analyses received from the McKinley typified the actual quality of coal received by APS.

APS subsequently conducted a similar study on coal samples and analyses taken at the Lee Ranch mine. This study also demonstrated a close correlation between samples taken at all locations, and confirmed that APS could have confidence in the validity of sampling and analyses results received from the mine.

APS takes samples at the Four Corners Station from the flowing stream of coal as received from the BHP conveyors at the station. APS takes one coal sample for approximately every 2,000 ton lot of coal received, using ASTM-certified coal sampling equipment. APS maintains two identical coal samplers. Each sampler operates in an automatic mode, and is computer controlled to collect representative samples. Coal is initially collected in 40-pound "milk cans" and then riffled down to produce two identical 2.2-pound samples, which are sealed in clear plastic bags. The bags are identified with sample numbers that include the date, sampler number, and sample sequence taken. One bag goes directly to the Four Corners lab for analysis and a second split of the sample is double bagged and retained in the sample tower building for storage as a referee sample. Liberty found the sample collection area and equipment to be clean and well maintained.

APS conducts all its coal sample analysis work at the APS Four Corners lab. Liberty's inspection of the laboratory found it to be well equipped and operated in a satisfactory manner. In similar utility coal analysis laboratories around the country, the outputs from sample analysis equipment are automatically fed into a computerized, laboratory data-management system, or directly into utility fuel-management systems. That approach minimizes opportunities for incorrect entry of sample analysis results into computer systems and the need for redundant handling of sample analysis information. APS has plans to manage sample analysis information in this manner; however, the current data management system is antiquated, and includes a number of manual steps in data recording, data crosschecking, data entry into a lab computer system, and eventual data entry into the main APS computer system. Testing of the new data management system is currently underway; APS personnel at the lab reported that full operation of the system should occur within approximately one month.

APS has engaged the services of an outside firm to provide an independent assessment of its coal sampling and coal analysis operations. Reports provided by this firm for both 2004 and 2005 indicate that the Four Corners laboratory continues to produce sound coal-sample analysis. This report also evaluated the APS sample collection system at the Four Corners Station, finding that it continues to produce sound results. The outside assessment found that the mechanical sampling system and the results of coal sample analysis from the laboratory met ASTM standards. This report also found the laboratory equipment and instrumentation to be in good condition, properly calibrated, and standardized. Laboratory personnel exhibited sound training and understanding of the importance of their responsibilities.

Liberty's examination verified that the personnel in the Fuel Procurement organization enforce contractual provisions related to coal quality. Data examined by Liberty showed that only two shipments to Cholla during 2005 and none in 2006 failed to meet Btu content specifications -- by a slight amount in each case. The lengthy history of good coal-quality performance from the McKinley mine made it unnecessary for APS to take corrective action. No 2005 or early 2006 deliveries to the Four Corners Station fell outside specifications.

<u>Information Monitored</u>

APS monitoring of coal quantity and quality information occurs in a number of places, including the Fuel Procurement organization, the generating stations, and the Four Corners Laboratory. Information on coal quality and quantity eventually drives payment amounts to coal suppliers. The Fossil Fuel Procurement Manager uses vendor-payment and cash-flow outputs from the APS computer system to monitor those payments. He is also responsible for the routine preparation of reports on fuel costs, quality, and quantity received by type, by supplier, by generating station, and for the APS system as a whole. The Fuel Procurement organization uses these fuel data reports, and provides a number of them to more senior management within APS. The Fuel Procurement Manager also has responsibility for verifying all invoices for fuel procurement and for quality-based adjustments to invoices, in order to ensure that they are in accordance with contract provisions and agreements.

3. Historical Supplier Performance

The two Supply Chain Managers and the Materials and Supply Analyst in the Fossil Fuel Management organization spend substantial time monitoring the performance of coal suppliers. The current coal contracts and purchase orders form the basis for this monitoring process. Responsibilities for monitoring this information are clear, and the information is available as necessary for this monitoring process. The information comes from reports generated by the APS computer system. The primary information monitored includes:

- Compliance of the suppliers with established delivery schedules
- Coal quantities specified by the contracts
- Coal qualities specified by the contracts.

<u>Force Majeure and Contract Disputes</u>

Force majeure provisions, while common, can produce physical or price disruption in utility fuel supply. Responding effectively to vendor claims is an important element in assuring reliable, economical supply. During 2005 and 2006 to date, APS did not face any counterparty claims of force majeure; therefore, APS experienced no situations requiring response in this period.

Disagreements with vendors are also inevitable over time. Managing them effectively is important in assuring effective long-term relationships with valued suppliers and in preventing transitory problems or disputes from having significant cost or reliability consequences.

There are no open or unresolved contractual issues involving coal supply for the Cholla Station. There is currently one open contractual issue involving Four Corners Station supply. It involves a [redacted].

There have been no non-performance disputes within the last five years. During the period from 2005 through 2006 to date, APS has not terminated any coal contracts due to non-performance. APS did, however, terminate the 2005 [redacted] The main agreement providing coal to Cholla is The Coal Supply Agreement of 2005. It is an extension of the P&M Amended & Restated Coal Supply Agreement of 2004, which the parties extended to add additional years of commitment in 2008 and 2009 as McKinley Mine's final reserves are identified. This extension replaced the need for the 2005 [redacted].

<u>Coal Quality</u>

The quality of coal delivered, as compared with specifications comprises a primary indicator of supplier performance. During the last five years, there has only been one instance where APS has rejected coal from a supplier. That case did not involve a regular coal supplier, but a Colorado supplier undergoing test performance. Given the very large quantities of coal delivered to APS on an annual basis (4.4 million tons to Cholla and 8.6 million tons to Four Corners), the dearth of non-compliant deliveries reflects strong supplier performance. APS's sourcing arrangements for coal, the absence of any adverse trends in supplier performance, and APS's attentiveness to supplier-performance issues give reasonable confidence that positive supplier performance will continue into the future.

4. Inventory Practices

Inventory Management

Cholla Station's October 2003 target was to maintain 35 days of coal in inventory The actual inventory level of 96 days far exceeded the target. An APS Audit Services review noted that [redacted] APS has since reduced the amount of targets and actual inventory at Cholla. The following table illustrates the Cholla coal inventory situation, measured in days of coal in inventory, as of January 2006:

Table III.1 Recent Cholla Inventory

Type of Coal	Target	Actual
Regular Sulfur	25 Days	26 Days
Alternative	25 Days	33 Days
Low Sulfur	30 Days	20 Days

The following chart displays the projected Cholla coal inventory, measured in tons of coal, for 2006. The chart illustrates the APS plan to manage coal inventory during 2006, and reflects the expected buildup of coal over the summer to meet increased demands for coal-fired generation during the summer months.

Table III.2 Projected Cholla Inventory

ENTIRE FOLLOWING TABLE IS CONFIDENTIAL

[redacted]

ENTIRE PRECEDING TABLE IS CONFIDENTIAL

The McKinley Mine produces Cholla's "Regular-Sulfur" coal, which any of the four units can burn. There are two types of "Alternative" coal. Alternative #1 coal (from Lee Ranch) has a higher ash and sulfur content than does McKinley coal. APS uses Alternative #2 coal (Spring Creek coal from the Powder River Basin) to address a precipitator issue. The Spring Creek coal has high sodium content. Over extended periods of time, the Unit #3 & #4 precipitators would become fouled as a result of sodium depletion in the precipitators. APS has found blending small quantities of the high-sodium Spring Creek coal with McKinley coal to be effective in combating precipitator fouling.

The McKinley Mine also produces "Low-Sulfur" coal for Cholla. Units #2 and #3 have a common emission requirement, but only Unit #2 has a scrubber. APS therefore holds the McKinley low-sulfur coal in reserve to supply Unit #3 when not operating in conjunction with Unit #2. With both units operating, the scrubbed emissions from Unit #2 and the unscrubbed emissions from Unit #3 combined still meet the state emission limit of less than 0.8 #SO_2/MMBtu. The APS long-range plan to [redacted] Unit #3 [redacted] would [redacted]

Space limitations constrain APS's ability to separate completely the different coal types inventoried there. APS maintains a separate low-sulfur coal pile. It does not strictly do so for the other coals, however. It maintains those coals in what essentially amounts to a single large pile, although APS can distinguish one coal from another by observing coal color and by using physical landmarks as references. This approach, however, does cause the coals to tend to commingle. The commingling presents operational challenges for coal yard personnel.

Four Corners presents an inventory situation that differs significantly. The Four Corners inventorying responsibility falls not to APS, but instead to the coal supplier. BHP must maintain adequate inventory to meet station needs. BHP maintains that inventory at the mine and at the BHP coal processing facility, which is located at the power plant. BHP must maintain sixty days of equivalent supply, which is approximately 1,200,000 tons of coal for Units #4 and #5. It must maintain at least 100,000 tons of that amount at the plant's blend piles. All of the coal is defined as usable, although coal in the pits and field stockpiles must be transported and processed at the BHP fuel handling facility at the power plant.

BHP has proven over the years to be reliable in meeting these requirements. Inventory data indicates that in 2005 and 2006 to date the minimum of 100,000 tons has always been maintained at the plant. The BHP mine lies approximately 15 miles south of the plant. BHP strip-mines from seven veins of coal, and transports to the plant via the mine's railroad. BHP maintains three locomotives and spare rail cars to ensure reliability. The railroad has no record of shutdown for operational reasons. It was shut down only once, many years ago, for five days due to regulatory reasons. Alternate truck transportation provides a backup source of delivery.

BHP crushes coal at a facility adjacent to the plant, and stacks it out in one of ten piles for reclaim and delivery to APS. Each reclaim pile, which contains approximately 28,000 tons of coal, can supply one day of operation of the Four Corners Station. Conveyors deliver coal to either one of two APS surge bins on a 24/7 basis. Coal can be conveyed to any one of the five units from the surge bins.

Inventory Measurement

Physical measurement of coal in inventory comprises an important component of electric utility fuel management. A utility should take inventory measurements on a regular basis to control effectively coal going into and from inventory. Uncertainty in inventory levels affects calculated efficiency of the generating station. Calculated efficiency needs to be accurate, for example, to assure proper location of the station in the economic dispatch order.

Typically, coal burning electric utilities undertake yearly comparisons of physical measurements and book amounts of coal in inventory at each generating station. Consistent trends in the variance calculated from such comparisons may indicate the existence of several problems; *e.g.*, measurements of coal going into inventory, measurements of coal leaving inventory, problems with the survey process, or problems preparing the coal pile for the inventory measurement. It is important to identify any existing problem source and to correct it.

Two primary methods can address variances between the book value of coal inventory and the physical inventory measurement. The "percent-of-pile" method calculates the variance amount as a percentage of the amount of coal in book value inventory. The "percent-of-burn" method calculates the variance amount as a percentage of the amount of coal burned by the generating station. The APS inventory surveys have used the percent-of-pile method.

In accordance with the agreement with PacifiCorp, the owner of Cholla Unit #4, a volumetric survey of the coal piles at Cholla is performed annually utilizing Global Positioning System ("GPS") survey techniques. The same contractor has performed the volumetric survey for the past several years. The surveys have generated a "base topography" of each of the piles from 32 base elevation points located around the piles. The surveys have then determined each pile's volume by taking several hundred GPS coordinates as the pile is traversed. The surveys have included annual analyses of coal-pile density and quality. Wet densities of the coal piles are measured at various depths and locations using a nuclear density gauge equipped with a depth probe. The survey contractor then has quantified the number of tons of coal in each pile by utilizing the volume information and the most recent density information. Cholla's "Regular" pile and the two "Alternative" piles are treated as one aggregate pile for the purpose of comparing and adjusting survey results. The physically separate "Low Sulfur" pile is treated separately.

Current procedures require an adjustment when a comparison of the GPS survey tons and the book inventory tons results in a deviation of greater than +/-5 percent. In that case, the book inventory tonnage is adjusted to the GPS survey tonnage prior to the end of the calendar year in which the survey is performed. The 2004 comparison of the aggregated piles produced a deviation of 5.367 percent, with the book inventory being the greater. Discussions with PacifiCorp led to agreement on a deferral of the required adjustment until the next GPS survey in 2005. This following survey showed much greater deviations: approximately 12 percent for the aggregated pile and 9 percent for the low sulfur pile. Again, book inventory was higher. An adjustment to the book inventory took place in December 2005. The following table summarizes the results of the 2004 and 2005 GPS surveys.

Table III.3 Cholla Power Plant – Coal Pile Survey Results 2004

	Regular + Alternative Pile Area				L/S Pile	
	P&M + Alt 2A Regular	Lee Ranch Alt 1A	Spring Creek Alt 2	Total Reg. + Alternative Coal Pile	Low Sulfur Coal	Total
Book Inventory - October 29	509,070	-	28,202	537,273	177,519	714,791
Coalpile Tons per GPS Survey	503,165	-	15,765	518,930	174,715	693,645
- Less Capitalized Base	(10,941)	-	-	(10,491)	(3,347)	(13,838)
Adjusted GPS Survey Quantity	492,674	-	15,765	508,439	171,368	679,807
Difference (Tons)	16,396	-	12,437	28,834	6,151	34,984
Difference (%) - 2004 Survey	3.22%	na	44.10%	5.37%	3.47%	4.89%

Table III.4 Cholla Power Plant – Coal Pile Survey Results 2005

	Regular + Alternative Pile Area				L/S Pile	
	P&M + Alt 2A Regular	Lee Ranch Alt 1A	Spring Creek Alt 2	Total Reg. + Alternative Coal Pile	Low Sulfur Coal	Total
Book Inventory - December 12	268,952	41,849	58,579	369,380	79,877	449,256
Coalpile Tons per GPS Survey	237,112	47,258	51,238	335,608	75,901	411,509
- Less Capitalized Base	(10,491)	-	-	(10,491)	(3,347)	(13,838)
Adjusted GPS Survey Quantity	226,621	47,258	51,238	325,117	72,554	397,671
Difference (Tons)	42,331	(5,409)	7,341	44,263	7,323	51,585
Difference (%) - 2005 Survey	15.74%	12.925	12.53%	11.983%	9.17%	11.48%

The results of these two surveys show the difficulty of accurately accounting for the three different coals maintained in the aggregated pile. The 2004 variance between book inventory and survey inventory for the Spring Creek coal pile was over 44 percent. This extraordinarily high variance did not likely result from scale calibration errors, but more likely from difficulty in determining the boundaries separating the Spring Creek "Alternative" coal. The survey results also show that book inventory values always exceed survey inventory values. Cholla either was burning more coal than the scales were measuring, or not as much coal was being received as the scales were measuring.

Cholla station management decided to conduct a further examination after observing the results of the 2005 survey. Operations and accounting personnel examined data from 2005 and 2006 to date. The 2005 data did not reveal any explanations; however, the 2006 data indicated a lack of sufficient correlation between weights of coal coming to the station and coal going into the units, indicating a potential need for scale adjustments. APS made adjustments; thereafter it has seen a nearly exact correlation between the weights of coal to the station and coal to the units.

Station management also decided to conduct quarterly GPS surveys in 2006 to confirm that it has addressed the inventory variance issue fully. The surveys require a nominal cost of $4,000. APS will continue to conduct the density portion of the survey, which costs $15,000, only annually.

5. Coal Combustion By-Products

The Cholla and Four Corners Stations generate a number of different coal combustion by-products: fly ash, bottom ash, and scrubber sludge. APS sells the material having commercial value, and disposes of the rest in landfills.

<u>Cholla Station</u>
APS stores fly ash collected dry in fly ash silos at the station. A contractor then ships approximately 90 percent of this material offsite in bottom dump trailers or in railcars. The remainder consists of the slurry collected in wet scrubbers and of fly ash that the contractor rejects (*i.e.*, does not ship). APS pumps this remainder to the Cholla Fly Ash Pond for disposal. APS collects bottom ash in the bottom of the boilers, grinds it, and pumps it as slurry to the Cholla Bottom Ash Pond. APS sells approximately [redacted] of the Cholla bottom ash. Non-marketable bottom ash remains in the pond. The table below shows the quantities of Cholla ash handled in 2005, the tons of ash sold, and the revenues received from these sales.

Table III.5 Cholla Power Plant: Ash Disposal Figures, 2005

Material	Disposed		Sold	
	Tons	Cost	Tons	Cost
Bottom Ash	[redacted]	[redacted]	[redacted]	[redacted]
Fly Ash	[redacted]	[redacted]	[redacted]	[redacted]

APS plans no changes in storage methods for the next 12 months, but eventual changes at Cholla Unit #1 will alter the ash handling process. A fabric filter baghouse will replace the current mechanical dust collectors and the wet particulate scrubber. Scheduled for startup in December 2007, the baghouse will allow collection and storage of additional dry fly ash for potential sale.

<u>Four Corners Units 1, 2, and 3</u>
APS removes all fly ash and SO_2 scrubber sludge from the flue gas by wet Venturi scrubbers, and decants it to about 40 percent solids in thickeners at the station. Pumps then move the fly ash and SO_2 sludge mixture from the thickeners to the Units 1-3 fly ash disposal ponds, which are located about one and one-half miles to the west of the plant site.

The fly ash removal process occurs on a continuous basis. After pumping the fly ash and SO_2 sludge mixture to the disposal ponds, APS completely decants it of all water through simple particle settlement in the disposal ponds. The decanted water flows by gravity to a lined holding pond for re-use in the station. The fly ash disposal pond and water-holding pond are constructed with bottom ash, and lined with local clay and an HDPR liner to prevent seepage. Full fly ash disposal ponds are capped and reclaimed.

APS removes bottom ash from Units 1-3 boilers by water sluicing, and pumps it to hydrobin silos for decanting. Decanted bottom ash is loaded daily into belly dump trucks by gravity, through a discharge valve at the bottom of the hydrobins. The trucks transport the wet bottom ash about one and one-half miles to the west of the plant to the Unit 1-3 fly ash disposal pond. These ponds are located at mine areas where the coal has already been extracted. The bottom ash is used continuously for the construction of the dikes for future Unit 1-3 fly ash disposal ponds.

The table below shows the quantities of ash handled from the Four Corners Units 1, 2, & 3.

Table III.6 Four Corners Units 1, 2, & 3: Ash Figures

	2005		Jan 2006	
Item	**Tons**	**Cost**	**Tons**	**Cost**
Bottom Ash	[redacted]	[redacted]	[redacted]	[redacted]
Fly Ash Disposed	[redacted]	[redacted]	[redacted]	[redacted]
Item	**Tons**	**Revenue**	**Tons**	**Cost**
Cenosphere Material Sold	[redacted]	[redacted]	[redacted]	[redacted]

<u>Four Corners Units #4 & #5</u>

APS removes fly ash from the Unit #4 and #5 baghouses, sells what it can to [redacted] as a concrete additive, and disposes of the remainder. All fly ash is handled with pneumatic transfer lines and transfer silos. No fly ash is stored for longer than one day. All fly ash from these units is hauled by truck from the on-site transfer silos to the BHP coal mine for back-fill into the mine pits where coal has already been extracted. In preparation for hauling, mixing pug mills co-mix the fly ash with expended scrubber slurry and SO_2 sludge from the scrubber thickeners. APS removes bottom ash from the boilers by water sluicing, and then pumps it to hydrobin silos for decanting. Each day, the decanted bottom ash is disposed of by the same methods used for the other Four Corners units.

The table below shows the quantities of ash handled from the Four Corners Units 4 & 5.

Table III.7 Four Corners Units 4 & 5: Ash Figures

	2005		Jan 2006	
Item	**Tons**	**Cost**	**Tons**	**Cost**
Bottom Ash	[redacted]	[redacted]	[redacted]	[redacted]
Fly Ash Disposed	[redacted]	[redacted]	[redacted]	[redacted]
Item	**Tons**	**Revenue**	**Tons**	**Revenue**
Fly Ash Sold	[redacted]	[redacted]	[redacted]	[redacted]

APS plans no changes in the next 12 months in Four Corners fly ash or bottom ash storage and disposal. However, future changes are planned. The preceding tables show that Four Corners ash disposal costs are currently about $[redacted], some of which is offset by ash sales. APS anticipates that after 2008, costs will increase to over $[redacted] per year, because BHP will begin hauling the waste to mined-out areas considerably farther from the Four Corners Station.

APS has studied a number of alternatives that may save costs over the long-term. APS conducted detailed economic evaluations of a number of alternatives, using a net present value approach:

- [redacted]

[redacted]

- [redacted]

[redacted]

  - [redacted].

6. Natural Gas and Fuel Oil Use

The table below shows APS energy sources in 2005 and those projected for 2006. The proportion of requirements estimated to be met by natural gas will increase, because the Company projects gas-fired units as the primary source (supplemented by power purchases) for serving new load.

Table III.8 Sources of Energy

Source	2006 Estimated	
	GWh	%
Nuclear fuel	8,942	27.7
Coal	13,241	41.0
Natural gas	6,581	20.4
Hydro/Solar	41	0.1
Purchased power	3,465	10.7

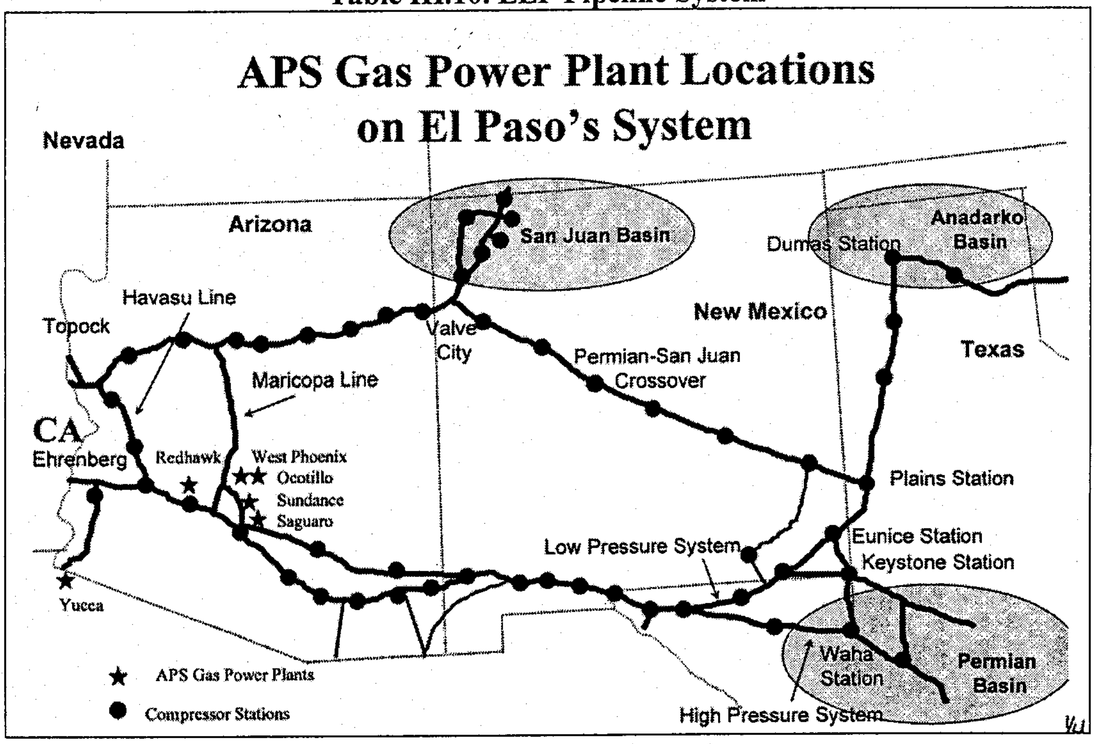
Gas has been a relatively more expensive fuel for APS; therefore, its contribution to total costs exceeds its contribution to total electricity production. The table below presents estimated 2006 expenditures for each fuel, including transportation and handling.

Table III.9 Energy Cost by Source

Source	2006 Estimated	
	$	%
Nuclear fuel	44,574	4.5
Coal	232,094	23.2
Natural gas	430,443	43.0
Hydro/Solar	0	0
Purchased power	294,285	29.4

At present, APS's only source of natural gas transportation is the ELP pipeline system, which the following diagram illustrates.

Table III.10. ELP Pipeline System



The map shows ELP system connections to three producing areas: the San Juan Basin, the Permian Basin, and the Anadarko Basin. For reasons of proximity and price, APS buys its gas from the San Juan and Permian Basins. About 70 percent of the Company's gas comes from the San Juan Basin. The prices are relatively lower there; transportation constraints prevent APS from buying more natural gas from this basin. The Company is trying to improve its access to the San Juan Basin, which a subsequent chapter of this report addresses.

APS also uses small amounts of fuel oil in some generating facilities. The Ocotillo, West Phoenix, and Yucca units can burn natural gas or No. 2 fuel oil (diesel fuel). Saguaro is also dual-fired, but uses residual fuel oil. APS burns gas for air-quality reasons, but maintains sufficient fuel oil inventories to provide two to three days of back-up in case the gas supply is interrupted. The Douglas unit, a diesel-powered reciprocating engine, runs only in the summer. Cholla uses a mixture of diesel and jet fuel for start-up. Palo Verde uses diesel for emergency back-up generators. The following table shows the oil burn in 2005 and projection for 2006 for those plants that make some use of oil. Palo Verde handles its own fuel oil inventories and usage, and does not report fuel use to APS's General Fuel Portfolio Management department.

Table III.11 Fuel Oil Use (MMBtu)

Station	2005 Actual	2006 Estimated
Cholla	[redacted]	[redacted]
Douglas	779	3,282
Yucca	2,581	2,527

7. Gas Purchasing Methods

APS M&T buys gas initially in the form of futures contracts. A futures contract provides the right to receive a fixed quantity of gas, delivered to a defined delivery point, at an agreed time in the future. APS buys primarily the standard contract that is traded on the New York Mercantile Exchange ("NYMEX"), which provides for 10,000 MMBtu, delivered uniformly over the month specified in the contract to the Henry Hub, a market center in Louisiana. APS also buys contracts to cover the difference in price between the Henry Hub and the market centers where it actually takes physical delivery of most of its gas: Blanco in the San Juan Basin and Waha Station in the Permian Basin. Purchasing these location differential contracts provides what are called "basis" hedges. These futures and basis purchases form an integral part of the Company's hedging strategy, which is addressed in detail in a later chapter of this report.

During "Bid Week", the Company sells the futures contracts that it holds for the month that is about to start (the "prompt" month"). "Bid Week" is the name given to the week before the start of a calendar month. During that week, gas suppliers and gas buyers agree on gas sales/purchases for the following month. Trading on the NYMEX in the "prompt" month futures contract also closes during this period. APS also liquidates its basis hedges during this period. APS uses the proceeds of that process to adjust gas purchase prices it has paid to reflect the difference between the value of the gas at the Henry Hub and that at the market centers on ELP.

After selling its futures contracts and basis hedges, APS buys physical gas at the ELP market centers. The combined effect of these transactions (futures contract purchases, futures contract sales, basis hedge purchases, basis hedge sales, and physical gas purchases basis) fixes the price of the gas for system use at the price of the futures contracts as of the time they are purchased. When the futures contract is sold and the physical gas is bought at the same time, the prices in those two transactions offset each other. The net effect of all of the transactions is that the price of the physical gas received is the price paid for the futures contract when it was bought.

APS purchases of physical gas during Bid Week call for uniform delivery over the course of the next month, just as futures contracts do. The Company's need for gas varies daily, however. This variability is a principal cause of a frequent need either to sell gas into the secondary market or to buy additional gas from that market, in order to match supply to requirements.

8. 2005 Gas Quantities Bought

APS determines the amounts of gas to be purchased by forecasting generation. APS uses a computer model to forecast generation and requirements for fuel and purchased power. APS prepares these forecasts for a seven-year horizon. The simulation model selects the optimum economic combination of power plant operation and power purchases, using power plant operating characteristics, actual fuel prices as far into the future as they can be determined, and forecast prices for periods beyond that.

The current strategy calls for gas acquisition to start [redacted] months in advance of the time that it is to be used. APS buys additional quantities as the delivery month approaches, until it has secured [redacted] percent of the anticipated quantity a full [redacted] months before the gas will be delivered. Target hedge levels apply to total energy to be bought, including both natural gas and purchased power. The hedges are generally about [redacted] to [redacted] percent gas, and [redacted] to [redacted] percent purchased power.

The following table shows 2005 budgeted and actual quantities of gas. The comparison shows strong overall correlation, but substantial monthly variability.

Table III.12 Forecast and Actual 2005 Gas Quantities

Month	Quantities Forecast	Quantities Used	Difference (% of forecast)
January	2,284,491	3,014,126	31.9
February	1,558,868	2,026,985	30.0
March	2,020,670	508,648	-74.8
April	2,168,036	3,480,511	60.5
May	3,975,882	5,568,442	40.1
June	5,519,733	5,748,773	4.1
July	7,351,188	7,665,043	4.3
August	7,792,391	6,787,717	-12.9
September	4,903,711	4,471,149	-8.8
October	3,809,537	5,007,104	31.4
November	3,467,319	2,969,108	-14.4
December	3,906,243	3,400,514	-12.9
Total	48,758,069	50,648,120	3.9

(MMBtu)

9. Dispatch and Measurement

After converting futures contracts to physical gas, APS M&T arranges delivery by the pipeline. The group nominates daily quantities from receipt points in the producing areas to delivery points at the generating facilities that the Company intends to run. Operation of each generating unit is determined on a day-to-day basis, depending on load conditions. The acquired gas is delivered ratably over the course of the month. On each day, any gas that is flowing under an agreement to purchase, but is not required to serve that day's load, is sold into secondary markets. Conversely, if additional gas is required, it is bought in secondary markets.

The pipeline company provides measurements at entry into and exit from the pipeline. Measurements at the receipt (inlet) points are compared by the APS M&T's back office to the invoices received from gas suppliers. The gas suppliers usually accept the pipeline's measurements. The pipeline calibrates most of its meters monthly. A representative from APS's Fuel Procurement department witnesses the calibrations at the delivery end. That person has a copy of ELP's *Metering Standards Guide*, and reviews ELP's invoices.

For quantities delivered, three sets of measurements are taken and compared:

- ELP's meter readings at its delivery points
- Meters on each gas-fired generating unit
- Measurement of each unit's electrical output.

The latter measurement is used in APS's transaction-tracking system (TranZ) to "back into" an estimate of the gas delivered to each unit, using its heat rate.

The Company's Generation Business Services department collects the three measurements into a monthly Fuel Reconciliation report. The Generation Engineering department, Fuel Procurement, and APS M&T's back office review this report. If any group has a concern, it addresses it with the other two, and then, if necessary, with ELP for resolution.

10. Fuel Oil Use

Diesel oil and jet fuel are readily available from numerous suppliers near APS's oil-using stations. APS enters into spot agreements with local suppliers to provide and transport required fuel oil supplies. Each generating station has sufficient storage to cover its requirements for two or three days. Inventory levels are reported daily to the Commodity Lead in General Fuel Portfolio Management. That person tracks usage, deliveries, and inventories, and then orders additional supplies when inventory at a particular plant is too low. Orders are placed with vendors having ongoing purchase orders on file with APS's Disbursement Accounting department. Prices are usually surveyed for a couple of days before the order is placed.

An oil products pipeline delivers to the West Phoenix plant site, where APS owns storage. An oil vendor operates that storage. Other plants receive supplies via tanker truck, except for Saguaro. That plant is the only one that uses residual fuel oil, which it receives by rail car.

C. Conclusions

1. APS has effectively administered coal contracts.

Responsibilities for fuel contract administration are well defined, appropriate systems are in place to administer fuel contracts, and the necessary data for this administration is available and properly used.

2. Manual processes in handling coal weight information are not efficient. (*Recommendation #1*)

Liberty found the processes for handling coal weight information to be inefficient, because they rely on multiple, repetitive data handling steps that could be better automated. There are no instances where coal weights are electronically fed into the APS computer system directly from the scales themselves. Similar inefficiencies exist at the Four Corners Station.

Electronic transfer of information at the Cholla Station directly from coal scales into the APS computer system could eliminate the following steps:

- One reading of an electronic digital meter

- Three different manual entries of the same information either onto paper, or into computers
- One scale printout of coal weight information
- One cross-check and comparison of printout information with manually read and written information
- Two instances where information is hand carried from one point in the process to another.

Because of the multiple and manual handling of coal weight information, there also are opportunities for entry of incorrect information. Because of these possibilities, APS has introduced steps of cross-checking in order to confirm that the weight information is correct. With more automated processes, these steps of cross-checking could be eliminated.

3. APS procedures for taking samples of coal at the Four Corners Station are sound.

APS uses appropriate ASTM coal sampling techniques and equipment. Coal samples are collected by an automated and computer controlled system. Samples are appropriately bagged and marked, referee samples are collected and stored, and samples are regularly transported to the coal laboratory a short distance away from the sample tower building. The sample collection area and sample collection equipment were clean and properly maintained. APS has engaged an independent firm to audit the entire coal sample collection and sample analysis process on an annual basis. The reports from these annual inspections have indicated that these systems continue to produce quality results.

4. APS has undertaken an appropriate program to automate the coal-sample analysis data-management process at the Four Corners laboratory; the program should be in place imminently.

The current coal-sample analysis data management process at the Four Corners laboratory is fairly antiquated. Data from the sample analysis equipment is manually recorded, and subsequently input into a stand-alone lab computer system. From this computer system, the data is printed out, and then re-entered into the APS computer system. In similar utility coal analysis laboratories around the country, the outputs from sample analysis equipment are either automatically fed into a computerized laboratory data management system that can communicate directly with utility fuel management systems, or are fed directly into utility fuel management systems. Thus, many current utility systems are highly efficient, and there is little opportunity for incorrect entry of sample analysis results into computer systems, or the need for redundant handling of sample analysis information. APS has plans to manage sample analysis information in this more efficient and more automated manner, and is currently testing a new data management system. APS personnel at the lab reported that full operation of the system should occur within approximately one month.

5. The Fuel Procurement Department has an effective process for monitoring supplier performance; the performance of these suppliers has been satisfactory.

Liberty found that the Fuel Procurement Department has been effective in managing the fuel procurement process and the material aspects of supplier performance. The responsibilities for monitoring this performance are clear, the monitoring systems are in place, and the data necessary for this activity is both accurate and available.

6. **The Fuels Department appropriately manages coal inventory, but its recent reduction in the inventory target for Regular Coal at the Cholla Station has been too large.** *(Recommendation #2)*

The Fuel Procurement Department recently lowered its Cholla Station coal inventory targets, and the amount of coal carried in inventory. A reduction was appropriate, but APS has set the Regular-Coal target at too low a level. APS has actually consistently managed Cholla Regular Coal inventories at levels exceeding the revised target. This lowered target calls for a 25-day supply, or about 212,500 tons. APS has appropriately been holding inventories at higher levels, given past supply-chain disruptions and the unpredictability it will face regarding coal deliveries over the next several years. Mine concerns will continue and perhaps escalate as the McKinley Mine winds down operations and the Lee Ranch Mine ramps up production. APS has projected inventory levels of Regular Coal at close to the current, 25-day target for the first three months of 2006, but projects that balances for the remainder of 2006 for Regular Coal will be approximately 90,000 tons greater than its target level of 212,500 tons.

7. **APS has taken appropriate action in response to recent variances between coal inventory book values and the results of physical inventory surveys.**

APS has an appropriate program for conducting annual physical surveys of the coal in inventory at the Cholla Station and for adjusting book inventory values annually if the variance between book values and physical survey results is greater than +/-5 percent. The results of the 2004 and 2005 physical coal inventory surveys indicated in both cases that the book inventory value exceeded the results of the physical survey. In 2005, the Analysis of inventory variance data was 12 percent for the aggregated coal piles and 9 percent for the low sulfur coal pile.

Cholla Station management conducted a thorough study to determine the cause or causes of such variances, and has taken appropriate action to make slight adjustments to some of the station's coal scales.

8. **APS has appropriately sought beneficial uses and sales of coal combustion by-products.**

Where possible, APS has used ash in the construction of its own dikes for ash disposal ponds. Ash is used on haul roads where possible, to provide improved road stability. APS has an ongoing program to sell some ash for use in cement production. In 2005, a total of approximately $[redacted] in revenues were received from sales of coal combustion by-products from Cholla and Four Corners.

9. **APS has appropriately sought alternative means for disposal of coal combustion by-products at Four Corners when faced with significantly increased disposal costs from BHP.**

Upon learning that the Four Corners disposal costs were going to [redacted] APS evaluated a number of alternative projects with the potential to [redacted]

[redacted] The projects were appropriately [redacted].

[redacted]

10. APS's historical approach to gas supply management is typical, but current circumstances constrain its ability to address changes from full-requirements service from the pipeline. *(Recommendation #3)*

Electricity generators tend to be different from other customers for gas pipelines' transportation services in at least two important respects:

- Generators use relatively large quantities of gas over relatively brief periods. Those periods occur at different times of the day: morning and evening peaks, and perhaps during the day between peaks, but not at night.
- Generators are relatively less sensitive to the cost of the pipeline services that they require, because (a) they may not have access to other sources of reliable electric energy when they need it to serve their loads, and (b) facilities modifications required for changing their patterns of use may be difficult or expensive to install.

With large amounts of gas flowing to California year-round, ELP has been able to accommodate APS's specialized requirements without difficulty. ELP's full-requirements service allowed APS's requirements to be served without distinguishing between APS's varying rates of take, and other customers' more-uniform off-takes. Now, more of ELP's load has shifted to its east-of-California markets. In addition, ELP's other customers are interested in shifting costs away from themselves. In these circumstances, the FERC's interest in unbundled services and pricing has brought changes to ELP's rates that will result in enormous increases in ELP's charges to APS. Indications are that using the pipeline in the same way will increase APS's bills for pipeline services from about $[redacted] per year to about $[redacted] per year. Unless APS finds ways to use less of ELP's newly-specialized services for electricity generators, it has little option but to pay the extra costs.

The first way to use less of the expensive services is to evaluate whether facilities additions or other usage changes might result in lower requirements for the specialized services. Liberty recommends that the Company analyze facilities additions and other changes that would have the desired effect, and present a report to the Commission.

11. APS's pursuit of additional pipelines is appropriate.

The other possibility for reducing APS's requirement for ELP's services is additional pipelines. Shifting part of APS's load to other pipelines may help directly, but perhaps also indirectly. Competitive alternatives may counteract ELP's tendency to shift costs to services that APS requires. Opportunities presented by additional pipelines should be part of the analysis that the Company presents to the Commission.

12. APS's approach to buying fuel oils is reasonable.

Procedures are appropriate and well documented. Processes appear to be working smoothly.

D. Recommendations

1. Streamline the procedures for handling of information on coal weights. (*Conclusion #2*)

A potentially attractive solution to this inefficiency in handling of coal weight information would be to modify the electronic outputs of coal scales, and procure the necessary interface equipment in order that these signals can be fed directly into the APS computer system. This enhancement would eliminate the multiple, redundant, and inefficient processes now used at Four Corners and Cholla. APS must evaluate the electronic outputs of each of its coal scale systems and determine the steps necessary to feed (if possible) this electronic information directly into the APS computer system. There will clearly be costs associated with such modifications, and the appropriate cost/benefit studies must be conducted. It is, however, Liberty's belief that the long-term benefits of such new processes will outweigh the short-term costs.

2. Revise the inventory target for Regular Coal at the Cholla Station from 25 days of supply to 35 days of supply. *(Conclusion #6)*

Revision of the inventory target for Regular Coal at the Cholla Station from 25 days of supply to 35 days of supply will acknowledge what APS is in effect already doing, and doing appropriately. The Company is addressing through inventory management the need to provide for the uncertainty of coal deliveries over the next several years. This change would increase the APS target for Regular Coal from 212,500 tons of coal to 297,500 tons of coal. This target should be maintained until 2009, at which time it will be appropriate to reconsider a downward revision of the target.

3. Conduct a comprehensive analysis of gas purchasing and management under ELP's revised rate structure, and report to the Commission. *(Conclusion #10)*

The very large increase in the prospective cost of ELP's gas transportation services warrants a thorough study of possibilities for reducing that cost. The list of possibilities includes, in addition to others that APS may identify:

- Addition or alteration of facilities at APS's generating stations that would have the effect of reducing the variations in flow required to operate APS's gas-fired generating units
- Participation in high-deliverability storage projects, in Arizona or elsewhere
- Identify gas users with complementary use patterns that might share pipeline capacity with APS.

Liberty recommends that the Company provide a report to the Commission on its investigations. As some alternatives are continuing to evolve, and the Company should have ample time to identify and evaluate others, Liberty recommends that the target date for completion of this report be set at one year.

IV. Fuel Contracts

A. Scope

This chapter of Liberty's report addresses the following topics related to Arizona Public Service Company's (APS) coal contracts:

- Procurement Processes
- Contract Summaries
- Renegotiation of Contracts.

Liberty's review of natural gas purchasing included an examination of gas-purchasing process descriptions and interviews of key personnel. Liberty examined a sample of contract files, and observed purchasing, sale, and scheduling operations on the trading floor. Liberty's fuel-oil purchasing review included examining purchasing process descriptions and procurement data and interviews of key personnel. The evaluation criteria included the following:

- Reasonableness of the procurement processes in the context of the markets in which they are conducted
- Reasonableness of market interaction levels and costs to ensure least-cost dispatch
- Reasonableness of supplier qualification processes
- Accuracy and completeness of fuel supply contract files.

B. Findings

1. New Cholla Supply Sources: 2005

The APS contracting position is not typical for electric utilities that burn large amounts of coal for power generation. The existing APS long-term contracts for its two major generating stations that burn coal have caused it not to be a routine, large participant in the supply market. More recently, however, APS has faced a need for more significant purchasing activity. In the past two years or so, APS has been acting to obtain new long-term coal supplies for the Cholla Station. Cholla was originally designed and built to burn coal from the McKinley Mine in New Mexico. This mine has been the predominant source of station supply since the 1960s, when the station began operation. More recent projections for the life of the McKinley Mine indicate that mineable coal reserves will not last as long as initially anticipated.

APS secured a 2004 amendment and restatement of the contract for supply from McKinley, and amended the contract again in 2005. These changes added commitment years of 2008 and 2009 as the McKinley Mine identifies its final coal reserves. At the same time that APS was amending the McKinley contract to cover final commitments from the mine, APS also began the process of procuring coal supplies that would support Cholla Station operation after the McKinley supply ended. APS issued a solicitation that produced eight proposals from four suppliers. The responders, listed below, offered a variety of sources, tonnages, and pricing provisions:

- Arch Coal – Black Thunder Mine in Wyoming – three different proposals
- Kennecott Energy – Spring Creek Mine in Montana
- Kennecott Energy – Jacobs Ranch Mine in Wyoming

- Oxbow Carbon & Minerals LLC – Elk Creek Mine in Colorado
- Peabody – North Antelope/Rochelle Mine in Wyoming
- Peabody – Lee Ranch & El Segundo Mines in New Mexico.

All of the new sources of supply identified in response to this 2005 solicitation offered coal with quality characteristics different from those of McKinley Mine coal. APS understood that selection of a new source would require station modifications at Cholla. APS analyzed this need by evaluating the necessary modifications, which differed for each potential source. This analysis estimated the capital and operating costs of the required modifications, and addressed the consequences of burning differing combinations of the various coals proposed. The evaluations also modeled BNSF rail transportation rates, in order to place the alternatives on a comparable coal-cost basis; *i.e.*, at the plant rather than at the mine.

APS finally compared the proposals on a net present value analysis in order to produce final rankings that considered more than the delivered cost of coal, but rather, the more relevant total cost to produce electrical energy. The comparison included:

- Each offeror's cost of coal
- Associated costs of transportation
- Required capital costs
- Estimated recurring O&M costs
- Costs of any unit derates
- Increases in auxiliary power.

APS decided that procuring 100 percent of its Cholla requirements from the Lee Ranch and El Segundo Mines of Peabody would be the best available options. APS estimated that coal from these mines would produce the lowest delivered cost ($[redacted]/MMBtu, in [redacted] dollars, as compared to $[redacted]MMBtu for McKinley coal). APS also determined that this coal would produce the smallest net present value cost over the life of the contract after adding in all of the associated, incremental capital and operating costs. APS and Peabody agreed on December 20, 2005 to a long-term relationship for the Cholla Station. The agreement includes a base price, in [redacted] dollars, of $[redacted]/ton, and will run from [redacted] through [redacted].

2. 2005 Short-Term Purchases from Peabody and Kennecott

APS made two additional short-term coal purchases in 2005. APS purchased 550,000 tons of Lee Ranch coal from Peabody and 50,000 tons of Spring Creek coal from Kennecott. APS made these purchases on a sole-source basis; it did not use a solicitation process.

APS made the Lee Ranch purchase to deal with supply constraints from McKinley. APS's 2005 projected requirements for Cholla were [redacted] [redacted] tons of coal. APS received notice that the McKinley Mine would not be able to deliver more than [redacted] tons during 2005. APS had to address a potential [redacted] shortfall. APS requested a proposal from Peabody for Lee Ranch Mines to supply the added tonnage. Peabody proposed in April 2005 a price of $[redacted] per ton for 550,000 tons of [redacted] Btu/lb coal from Lee Ranch. APS found this price to be sufficiently competitive, given that Peabody's bid (at roughly the same time) for supply of the same coal on a long-term basis to the Cholla Station was $[redacted]/ton, in [redacted] dollars. Subsequently, APS and Peabody signed a short-term coal supply agreement with a term from May 10, 2005 to December 31, 2006, for provision of 550,000 tons of coal from Lee Ranch to Cholla.

APS did not use a solicitation for Kennecot's Spring Creek coal because of its unique nature and significance to Cholla Station operation. The coal's high sodium content makes it beneficial in solving precipitator-fouling problems when blended with other coal for use at Cholla Units #3 and #4. Over long periods of operation, the Cholla Units #3 and #4 precipitators become fouled due to sodium depletion in the precipitators. When relatively small amounts of the Spring Creek coal are used in these units, the high sodium content of the coal enhances precipitator operation and APS is able to achieve extended periods of operation without taking the units off line. APS has not found another coal that contains such high levels of sodium.

APS already had a January 1, 2004, open-ended purchase agreement with Kennecott for unspecified quantities of coal to be delivered in the future, at prices to be determined on agreement between the parties. APS used this "Master Agreement" for the purchase of the 50,000 tons of coal from Kennecott. In the fourth quarter of 2004, APS requested that Kennecott prepare a proposal for delivery of 50,000 tons of Spring Creek coal for delivery to Cholla during the first quarter of 2005. Kennecott proposed a price of $[redacted] per ton for 50,000 tons of [redacted] Btu/lb coal in December 2004. Cholla's inventory of Spring Creek coal was then at only 15,000 tons. Because of its regular contact with the market for this coal, APS believed that this was a fair price for the coal required. After the fact, the APS assessment of the market proved was corroborated. A few months later the Kennecott bid for supply of this same coal on a long-term basis to the Cholla Station was $[redacted]/ton, in 2008 dollars. APS confirmed the purchase with an agreement letter signed by the Director Fuel Procurement. Approval of a commitment of this nature was within the Director's established authority limits.

3. Summary of Current Coal Contract Portfolio Summaries

Current Cholla Supplies

A contract with P&M Coal Company provides for primary supply to Cholla Station. This contract is an amended and restated agreement dated January 1, 2004. The agreement runs through December 31, 2006, and provides for the wind-down at McKinley Mine as it reaches the end of its operations. The following table summarizes total contract tonnages. The contract also allows for up to [redacted] tons of low-sulfur coal each year, if available. The following table shows the Contract Base Pricing.

Table IV.1 P&M Contract for Cholla Coal Supply

2004	Tons	2005-2007	Tons	2008-2009	Tons
TOTAL	[redacted]	*TOTAL*	[redacted]	*TOTAL*	[redacted]
Tier 1	[redacted]	Tier 1	[redacted]		
Tier 2	[redacted]	Tier 2	[redacted]		
Tier 3	[redacted]	Tier 3	[redacted]		

Table IV.2 P&M Contract Base Pricing

Year	$/Ton
2004 – 2007 - Tier 1	[redacted]
2004 – 2007 - Tier 2	[redacted]
2004 only– Tier 3 (first [redacted] tons)	[redacted]
2004 only– Tier 3 (second [redacted] tons)	[redacted]
2005 – 2007 Tier 3	[redacted]
2008	[redacted]
2009	[redacted]

The Base Prices escalate annually, based on two indices combined: [redacted]. The price also adjusts monthly for Btu content, based on monthly weighted averages around a target Btu content of [redacted] Btu per pound. The contract also provides for price adjustment if the ash content exceeds [redacted] percent in more than three trainloads per year, and a price adjustment for sulfur if the sulfur content of the coal is above [redacted] $\#SO_2/MMBtu$ in more than [redacted] trainloads per year. Payment for the coal is based on weights and samples taken at the mine. The contract also contains other standard provisions typically found in coal supply agreements. The agreement is typical of agreements of this type.

In addition to this contract, APS also has the two, previously discussed short-term contracts for the 2005-2006 time period:

- 550,000 tons of coal from the Peabody Lee Ranch Mine
- 50,000 tons of coal from the Kennecott Spring Creek Mine.

<u>Future Cholla Supplies</u>

This long-term contract runs from January 1, 2006 through December 21, 2024. Its term and deliveries are integrated with the existing McKinley Mine supply. The tonnages under the new agreement increase annually as McKinley operations wind down. Coal will come from the Peabody Lee Ranch and El Segundo Mines in New Mexico. The following table summarizes the contract tonnages.

Table IV.3 Peabody Cholla Contract Deliveries

Year	Yearly Tons
2006	[redacted]
2007	[redacted]
2008	[redacted]
2009	[redacted]
2010 – 2024	[redacted]

[redacted]

The Base Price under this coal supply agreement is $[redacted] in [redacted] dollars, with quarterly adjustments under seven different indices that relate to coal production operations. There are price re-openers in the years [redacted], callable by either party, upon which prices are to be renegotiated. The price also adjusts for Btu content on a monthly weighted average basis around a Btu target of [redacted] Btu/pound. The following table shows required coal quality measured on monthly weighted-average basis.

Table IV.4 Coal Quality

Monthly As Received Quality		Rejection Limits
Moisture	[redacted]	[redacted]
Ash	[redacted]	[redacted]
Btu	[redacted]	[redacted]
SO_2	[redacted]	[redacted]
Mercury	[redacted]	[redacted]

Payment for the coal is to be based on weights and samples taken at the mine. The contract also contains other standard provisions typically found in coal supply agreements. The agreement is typical of contracts of this type.

<u>Four Corners Coal</u>

Four Corners supply comes from a surface mine located adjacent to the station. This mine has been supplying station coal since initial operation in the early 1960s. The original, August 18, 1960 coal supply agreement covered Units 1, 2, and 3. A September 1, 1966 Fuel Agreement Number 2 covered Units 4 and 5. Both agreements, with BHP Navajo Coal Company, were recently renegotiated, dated August 31, 2003. Their new terms run from January 1, 2005 through July 6, 2016. These mirror agreements give APS extension rights for a term of not more than 15 and not less than 5 years. Pricing under any contract extension will be by negotiation.

Delivery quantities are to be not more than [redacted] tons/day (or in excess of [redacted] per hour) of [redacted] Btu coal. BHP's contractual obligations are to maintain sixty days of equivalent supply, which amounts to approximately 1,200,000 tons for Units 4 and 5. At least 100,000 tons of that amount must be maintained at the blend piles at the plant. Monthly average contract qualities are:

Table IV.5 Monthly Average Contract Qualities

Monthly As Received Quality		Rejection Limits
Moisture	[redacted]	[redacted]
Ash	[redacted]	[redacted]
Btu	[redacted]	[redacted]
Sulfur	[redacted]	[redacted]
Volatile		[redacted]
Alkali as Na2O		[redacted]

The contract price is the sum of the following [redacted] components, specified in cents/MMBtu: [redacted]

4. Renegotiation of Coal Contracts

Between 2005 and April 2006, APS renegotiated three of its coal supply agreements. The following sections summarize them.

Cholla Coal Supply
The P&M Amended & Restated Coal Supply Agreement of 2005 is an extension of the P&M Amended & Restated Coal Supply Agreement of 2004. The contract was extended to add additional commitment years of 2008 and 2009, as McKinley Mine's reserves are identified. The contract pricing for the years 2005 and 2006 did not change as a result of this extension.

Four Corners Coal Supply – Agreements #1 and #2
The Restated and Amended Four Corners Fuel Agreement #1 extends the Four Corners Units 1,2,3 Restated Coal Supply Agreement of January 20, 1992. The original agreement required extension or expiration. The Restated and Amended Four Corners Fuel Agreement #2 is an extension of the Four Corners Unit 4 & 5 Restated Coal Supply Agreement of January 20, 1992. The original agreement also required an extension or expiration of the agreement.

The key provisions achieved through renegotiation of the Four Corners agreements were the [redacted].

5. Natural Gas Commodity Procurement

Natural gas fuels over 50 percent of APS's generating capacity. That capacity runs primarily in the warmer months, however. Gas therefore provides only about 20 percent of the energy that APS uses to provide electricity to its customers. However, natural gas is a relatively expensive fuel in the APS mix. Therefore, it represents over 40 percent of the Company's 2006 budget for fuel and purchased power, even after giving effect to the considerable hedges acquired to limit price, and after considering FAS 133 mark-to-market reversals.

The El Paso Natural Gas Company ("ELP") pipeline system is the only significant APS option for delivering gas to its generating facilities. A 1996 rate settlement fixed APS's obligation for ELP's costs through December 31, 2005. However, the FERC altered the full requirements provision of the 1996 settlement effective September 2003. Since 2003, APS has been working with ELP and other pipeline customers to determine APS's cost responsibility after the end of that settlement, and under ELP's current rate case filed June 30, 2005 at FERC.

APS does not use bid solicitations or requests for proposals to buy physical gas because of the liquid nature of the market centers where it buys its gas. APS's gas traders select offers through an online trading system (the InterContinental Exchange, or "ICE") or through telephone contacts. APS transacts with suppliers with whom the Company has a master gas-purchase agreement in place, and from that list limits transactions to those who remain within the individual credit limits determined by APS.

The traders initially buy in month-long blocks for delivery at a uniform rate over the course of the delivery month. APS uses fixed and index pricing in comparable proportions for these purchases. APS makes most of these agreements to purchase during "Bid Week," which consists of the few days before the end of each month when buyers and sellers in the market generally agree on transactions for the following month. APS does make some purchases with delivery periods exceeding one month. These longer agreements, however, provide for re-pricing at the beginning of each new month.

Within a given delivery month, APS may make supplemental, shorter-term (*i.e.*, "intra-month") purchase or sales, in order to keep its supplies in line with its needs. APS uses the same ICE-or-telephone process for intra-month purchases and sales. A typical intra-month gas purchase would include a several-day purchase or sale to respond to a change in electric load from forecasts. A typical intra-month gas sale would consist of a gas sale when an accessible supply of inexpensive power comes on the market. These sales take advantage of greater economy in buying power and selling gas, versus burning it in the operation of a generating unit. APS continually optimizes the "value" of its gas portfolio by examining and responding in the marketplace to changing natural gas prices relative to electricity prices and available opportunities.

APS uses industry-standard form contracts to buy physical gas. Recent agreements use the North American Energy Standards Board ("NAESB") Standard form 6.3.1, dated April 19, 2002. That form consists of a base contract for purchases and for sales of natural gas. It contains general terms and conditions for purchases and sales and a standard form "Exhibit A", which is used to confirm specific transactions. Such confirmations operate as an industry-standard means of verifying for both parties the existence of a "deal" and of those principal terms (*e.g.*, price, firmness, quantity, delivery point) not addressable in the standard form contracts. APS requires a fully executed form contract to be on file for each authorized counter-party.

Before the NAESB contract, APS used a Gas Industry Standards Board ("GISB") form or a Master Agreement for Purchase/Sale. APS may still use an older agreement for a counter-party with whom it does not trade much, if the older form can address current transactions adequately. For counter-parties with whom it is actively trading, APS uses the current form agreement.

The principal criterion for qualifying potential suppliers to supply gas to APS is credit standing. APS qualifies prospective suppliers under a credit analysis process that applies both quantitative and qualitative factors. APS uses a proprietary *Credit Review Model* to analyze various credit factors. Quantitative factors include financial leverage, liquidity, capital structure, and performance analysis. Qualitative factors include product diversity, risk-management capability, regulatory environment, and growth prospects. APS grants an unsecured credit line to those suppliers for whom the credit analysis reveals "investment-grade" credit. Non-investment-grade suppliers must post collateral or secure APS manager approval in order to transact with APS.

APS keeps its vendor list current with the use of its TranZ deal-capture system. Credit reviews of all fuel vendors occur at least annually, and more frequently when deemed necessary. The deal-capture system prevents transactions with unauthorized vendors or with vendors over their credit limits with APS. The ICE electronic trading platform provides for coding credit limits for specific counter-parties. The APS "middle office", the Energy Risk Management department, has responsibility for keeping that coding current every day. The following tables list the Company's top 10 counter-parties for gas purchases and sales in 2005.

Table IV.6 Top Ten Counter-parties for Gas Purchases, 2005

Company	Quantity Purchased
[redacted]	[redacted]

Table IV.7 Top Ten Counter-parties for Gas Sales, 2005

Company	Quantity Sold
[redacted]	[redacted]

APS "enabled" (qualified for purchasing) eight new suppliers in 2005, and started buying from one of them (IPC (USA), Inc.). Six new suppliers were enabled in 2004. As of the end of March, APS had added no new suppliers in the first quarter of 2006.

6. Gas Transportation

APS currently transports gas only through the ELP pipeline system. APS's bills from ELP, totaling $[redacted] per year, have been essentially the same for about a decade, due to the 1996 ELP settlement. The period of that settlement expired at the end of 2005. APS took full-requirements service from ELP until the fall of 2003. The full requirements relationship gave APS considerable flexibility in receipt and delivery points. APS could vary quantities for delivery to its power plants in response to variations in its electric load.

In September 2003 the FERC required ELP to convert its full-requirements contracts to the more-typical contract-demand-type service agreements. APS experienced no change in its cost responsibility under that conversion, but lost its receipt/delivery points and delivery-quantity flexibility. Since that change, APS has had monthly contract demand levels developed from its use patterns in a test year.

At the end of June 2005, ELP filed a rate case at the FERC, for new rates to go into effect after the end of the settlement period (*i.e.,* the start of 2006). Full implementation of the new rates has been deferred several times, but the majority of new tariffs for services are now in place. The case still remains open and settlement discussions continue as well. The new services that APS would take under the ELP proposal now have hourly flow provisions and penalties for violating those provisions. The new services also have hourly and daily balancing provisions, whereas the full-requirements service only required APS to balance monthly. Balancing is the requirement to put the same quantity into the pipeline that a customer takes out. When only monthly balancing was required, APS could spread its efforts to adjust quantities bought and injected into the pipeline to equal quantities withdrawn over an entire month. With daily or hourly balancing, APS has to find a way to vary the quantities that it is buying and injecting into the pipeline to match the quantities that it is withdrawing on a daily or hourly basis.

APS estimates that the combined effect of these changes could raise APS's ELP costs from the old $[redacted] to [redacted] per year. The APS 2006 budget for fuel and purchased power shows estimated charges for gas transportation of $[redacted] million. APS transports gas through ELP under nine firm gas-transportation contracts and two interruptible contracts. APS has been considering its options in response to the conversions and the new rates. APS had not by the end of the first quarter of 2006 executed any of the firm contracts. Three of the firm contracts had previously been executed: two associated with the Sundance power plant purchase, and one associated with a recent expansion of ELP's system.

Storage is one potential option for addressing the new ELP pricing structure. Pinnacle West Energy Corporation ("PWEC"), APS's former merchant-energy affiliate, sought to develop a high-deliverability storage project in an underground salt deposit near Luke Air Force Base on the west side of Phoenix. High-deliverability storage can accommodate the large changes in flow rates that characterize combustion turbine operation. Such a facility would assist materially in meeting ELP's new balancing requirements economically. ELP acquired the project from PWEC; however, legislation enacted in 2004 prevented further development.

APS is pursuing new pipeline options. In December 2005, APS signed a precedent agreement with Transwestern Pipeline Company ("TRW") to take capacity on a new pipeline project connecting the San Juan Basin to the Phoenix area. The applicants expect to file for FERC approval this summer. TRW's target in-service date is April 30, 2008. That project could serve Redhawk and Sundance generating stations. It would apply balancing requirements much less stringent than those of ELP's new services.

APS is also addressing options with the [redacted] APS hopes to [redacted]

7. Fuel Oils

APS uses very small quantities of fuel oils. Most of the reported use in 2005 was for start-up fuel at the Cholla generating station, which is coal-fired. APS used smaller quantities in the summer at the Douglas and Saguaro generating stations. APS does not use bid solicitations or requests for proposals to buy fuel oils or oil transportation. There are a number of suppliers near each power plant. APS places an order to an authorized supplier when additional supplies are required, after surveying market prices for several days.

APS uses its own contract for oil purchases. The Company has contracts for the purchase and sale of No. 2 diesel fuel and No. 6 residual fuel. The contracts set forth general terms and conditions; *e.g.*, title transfer, transportation and balancing and the exercise of options, billing and payment, events of default and remedies. APS generally buys fuel oils on a delivered basis; therefore, it includes the cost of transportation in the agreed price. APS styles these contracts as master purchase and sale agreements, with oral transactions under them to be followed by facsimile confirmations specifying transaction-specific terms. Each contract attaches a sample form "Exhibit A" to be used for the confirmations. Exhibit A provides for specification of price, quantity, delivery point, period of delivery, and any other transaction specific terms.

C. Conclusions

1. APS applied an appropriate process for the procurement of new long-term coal supplies for the Cholla Station.

In February 2005, the Fuel Procurement organization issued an RFP for new coal supplies for the Cholla Station, with deliveries to begin in 2008. The RFP was necessary because the current coal supply from the P&M McKinley Mine was predicted to end in 2009. The RFP was sent to the major coal suppliers in New Mexico, Colorado, Wyoming and Montana capable of responding with the volumes of coal required. APS also requested that BNSF provide an offer for coal transportation services for the Cholla Station from the anticipated supply regions. APS conducted a thorough analysis of bids received for coal supply and for transportation, and integrated these bids into an economic analysis. This analysis determined the lowest overall cost to produce electrical energy from the various coals proposed, when all of the new capital and operating costs at the Cholla Station were considered. The process used by APS was reasonable, considering: the timing of the need for coal, the extent of the modifications required at the Cholla Station, the potential coal suppliers contacted, the analytical process used to determine the optimum combination of coal supply and plant modifications, and the provisions of the finalized coal supply agreement.

2. APS's long-term coal supply agreements providing the primary supply to the Cholla and Four Corners Stations are effective.

The coal supply agreements providing the primary supply to the Cholla and Four Corners Stations are as follows:

Cholla:

- The P&M Amended & Restated Coal Supply Agreement of 2005
- The Peabody Agreement dated 12/21/2005

Four Corners:

- The Restated and Amended Four Corners Fuel Agreement
- The Restated and Amended Four Corners Fuel Agreement #2.

These coal supply agreements are typical of the vintage of coal supply agreements that they represent and have been negotiated, or renegotiated, in an appropriate manner. The agreements provide a reasonable balance between the needs of both Buyer and Seller, and contain the types of protective provisions that one would expect to find in coal supply agreements of this nature.

3. APS's two short-term coal supply agreements for the Cholla Station are appropriate.

APS currently has two short-term agreements for supply of coal to the Cholla Station (the 550,000 ton agreement with Peabody for coal from Lee Ranch, and the 50,000 ton agreement with Kennecott for coal from Spring Creek). Each agreement was required for short-term supply situations at the Cholla Station, and was appropriately entered into considering the unusual supply constraints that APS was facing at the time. The terms and conditions of each of these agreements are also appropriate.

4. APS uses a sound process to contract for gas commodity.

APS gas purchase amounts approach $500 million annually; therefore, the contracting process for gas deserves major attention. APS provides the requisite level of attention. The procurement process with a new counter-party begins when an APS trader fills out a "vetting" form requesting authorization to trade. Credit and other analyses follow, culminating in a signed contract if both parties agree. Trading is generally not authorized until all documents are in place.

APS also administers its contracting process effectively. APS has knowledgeable and capable staff people managing the contracting process. Contract files are orderly and complete. APS M&T's Compliance function actively monitors compliance with relevant guidelines and procedures, and the "middle office" actively monitors credit and other risks.

5. The Company's efforts to develop alternatives to ELP have been appropriate.

The industry generally faces a significant problem in: (a) developing gas transportation and ancillary services, such as balancing, for electric power generation (particularly combustion turbines), and (b) pricing them fairly. The Commission's Staff has addressed this aspect of the problem in its *Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project*, filed in Docket No. E-01345A-05-0895 on March 2, 2006. (See especially p. 8.) The very substantial differences between ELP's services and pricing in this area and those for the TRW's proposed Phoenix Project show that the issues are perhaps more about cost incidence and bargaining leverage than they are about physical aspects of providing the services.

The ELP situation compounds the problem, given difficulties with its California markets. Those problems have given, and will continue to give, ELP a tendency to shift costs to its east-of-California markets whenever possible. ELP's rate proceedings at the FERC offer a forum for seeking protection from this tendency, but when parties (including most everybody but APS) present the FERC with a settlement, it is difficult to expect that the FERC will overturn it.

In those circumstances, APS has little alternative beyond paying the higher costs or trying to reduce its reliance on ELP. It is particularly difficult to use dramatically less of the types of services at issue, because APS is increasingly using its gas-fired generation as load continues to grow at a very fast rate. APS effectively must work as best it can with ELP in the short run, while aggressively pursuing its options for the longer term.

APS (and its affiliates) have been aggressive about developing options for the longer term. APS spent considerable effort on the Silver Canyon Pipeline Project in 2003 and 2004. The Commission approved the Company's application to participate in this project in Decision No. 67239, issued September 15, 2004. TRW's Phoenix Project has involved a similar effort, which the Company addressed with the Commission in its application filed in Docket No. E-01345A-05-0895 on December 16, 2005. The Company's efforts with the [redacted] have the potential for yielding additional diversification. TRW's Phoenix Project and a connection to [redacted] would provide sufficient access to other pipelines to carry over [redacted] percent of APS's maximum daily gas consumption.

High-deliverability gas storage is especially valuable to the operation of combustion turbines because of its ability to accommodate the large changes in flows. Continuing to address that option therefore has substantial merit as well.

6. APS's contracting process for fuel oils is appropriate.

APS's processes for managing its requirements for fuel oils are appropriate to the level of that activity. As discussed in the chapter on fuels management, APS's procedures in this area are sound and well administered.

D. Recommendations

Liberty has no recommendations in this area of examination.

V. Hedging and Risk Management

A. Scope

Liberty examined the goals, strategy, procedures and practices of the Company's hedging program. The principal questions addressed by our review were the following:

- What are the objectives of the Company's hedging program?
- Are they clearly defined?
- What strategies and instruments (futures, options, etc.) are used in pursuit of the Company's objectives?
- What are the qualifications of Company personnel involved in hedging activities?
- Are the Company's transaction-tracking capabilities adequate to the task of controlling and managing the Company's hedging program?
- What policies and procedures are used for managing the risks associated with the Company's hedging program?

B. Findings

The Company's hedging program was formed in 1996, in response to early signs of instability in power markets in other parts of the United States. APS was also experiencing increased exposure to price instability, as its requirements for natural gas and purchased power to supply its own markets were increasing. By 2003, the Company had established formal guidelines for the level of hedge protection for those requirements. Those guidelines provided for coverage extending out [redacted]. Today, the Company formulates its *System Hedge Strategy* annually. APS M&T recommends a strategy, including specific targets, and senior management reviews and approves it. The target hedge levels reflect an identified percentage of the Company's anticipated consumption of natural gas and purchased power. APS does not use separate limits for each, but sets the targets as a percentage of the expected or forecasted total of natural gas purchases and purchased power combined.

APS M&T manages the hedging program. The group uses weekly forecasts of volumetric exposure to natural gas and purchased power. APS M&T places hedges to fix the prices of the targeted percentages of gas and power expected to be required over the next [redacted]. The *System Hedge Strategy* and the *Target Hedge Levels* control the timing and magnitude of hedge positions. The Company's Energy Risk Management department monitors the hedge position relative to the targeted hedge levels, and prepares a monthly compliance report for the Company's Energy Risk Management Committee.

1. Goals and Objectives

The primary objective of APS's hedging activity has always been to increase stability in the rates that the Company charges its customers for electricity service. Attaining that stability has produced a hedging program aimed at managing the volatility of natural gas and purchased-power prices toward stability, as well. APS M&T tries to enter hedge positions at the lowest prices available, and correspondingly seeks to buy natural gas and power at the lowest prices available. APS M&T also works to lower fuel costs by optimizing the energy source used to serve system load and off-system sales. APS does not time or size its hedge positions with the goal of lowering costs, however, but of reducing volatility in fuel costs.

The Company does not use quantitative measures of price stability in setting objectives for its hedging program. Such measures might include a focus on limiting volatility to a certain percentage, or instituting price stability measures only when volatility exceeds a specified percentage. The current *System Hedge Strategy* focuses instead on fixing the price of defined proportions of the Company's requirements for natural gas and purchased power in advance of estimated needs for them.

An outside expert reviewed the [redacted]. That review [redacted]:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted].

2. Hedging Strategies and Instruments

Company purchases of coal and nuclear fuel take place under long-term contracts that APS considers to have stable pricing provisions. These arrangements thus provide a natural, or physical, hedge for an estimated [redacted] of 2006 fuel and purchased-power expenses. APS therefore does not undertake any hedging involving those fuels. Its active hedging program addresses natural gas and purchases of electric power, which comprise the remaining principal

[1] Arizona Corporation Commission Decision Number 61225 (October 30, 1998). See pp. 28-29.

components of its primary energy mix. Those components account for the other [redacted] of estimated fuel and purchased-power expense for 2006. Combining the natural hedges associated with the pricing provisions in its contracts for coal and nuclear fuel and the hedges purchased for natural gas and power produces the following results:

- [redacted] percent of total energy requirements are hedged for 2006
- [redacted] percent are hedged for 2007.

The Company's hedging strategy has been to fix the prices of the natural gas and purchased power that it requires through the use of forward contracts, energy futures, and swaps. The definitions of these instruments are:

- *Forward contract:* A bilateral contract in which buyer and seller agree on delivery of a specified quantity to a specified point at a specified price (or pricing mechanism) at a specified date in the future.
- *Futures:* A contract to buy or sell a fixed quantity of a commodity, delivered to a specified location, at a specific time in the future. Futures contracts are standardized, to allow their trading on public exchanges, such as the New York Mercantile Exchange ("NYMEX"). The right to receive (or deliver) the amount of the commodity covered by the contract is traded; the price of the commodity actually delivered is set at the time that trading in the contract closes.
- *Swaps:* In general, swaps are bilateral contracts in which buyer and seller agree to exchange an asset or liability for a similar asset or liability for the purpose of lengthening or shortening maturities, raising or lowering interest rates, or maximizing revenue or minimizing financing costs. APS reports that its swaps are "NYMEX look-alikes", negotiated directly with individual counter-parties, rather than bought on the exchange.

APS generally purchases power at delivery locations on its transmission system, such as Palo Verde and Four Corners. The price of that power can be hedged (fixed) at those locations. APS makes most of its purchased-power hedges as forward-purchase contracts at the Palo Verde location. APS generally buys natural gas, however, at the San Juan and Permian Market Centers on the El Paso Natural Gas ("ELP") transmission system, in New Mexico and West Texas, respectively.

The NYMEX futures contract for natural gas settles at the Henry Hub, a market center in Louisiana. Prices can differ at the delivery locations more directly relevant to getting the gas to APS, however. Transportation cost differences and constraints are examples of the reasons for those differences, which the industry refers to as "basis." APS manages these potential differences by also hedging (in addition to its hedging of the differences in futures prices of the gas commodity at the Henry Hub) its exposure to location, or basis, differentials between the ELP market centers and the Henry Hub. Various financial institutions "make markets in" (*i.e.*, buy and sell) basis differentials between the Henry Hub and other market centers; APS M&T places its basis hedges with several of those institutions.

Beginning in 2003, the Company adopted formal guidelines setting the proportion of its requirements for gas and purchased power for which prices would be fixed. With escalating volatility in energy markets and an increasing proportion of its power-supply portfolio exposed to those markets, APS increased those proportions in 2005. The proportion of APS's power supplies exposed to short-term energy markets increases because the growth in its load is generally accommodated with increased operation of its gas-fired generation, or increased purchases of short-term power.

Effective in late June 2005, the Company raised its hedge targets for its [redacted] ([redacted]) window as follows:

- [redacted] percent of forecast gas and purchased-power requirements will be hedged for the subsequent [redacted]
- [redacted] percent of forecast gas and purchased power will be hedged for forward [redacted]
- [redacted] percent of forecast gas and purchased power will be hedged for forward [redacted]
- Additionally, the Company will hedge [redacted] percent of its natural gas basis for the next [redacted].

The required hedge levels apply to total combined natural gas and power purchases. The lower percentages in the more-distant future periods recognize that volatility can be more pronounced in the near months. Futures prices for all periods tend to be affected when market-moving events, such as the hurricanes of 2005, occur. Prices farther into the future tend less to be affected by such events. The lower percentages for the fifth and subsequent quarters allow the Company's traders to wait for disturbances to subside before locking in prices for those periods.

The consultant that reviewed the Company's [redacted]

The [redacted] -percent target for the immediately ensuing [redacted] recognizes the uncertainty in the Company's load forecasts (and thus the uncertainty in its requirements for gas and purchased power). The Company re-estimates weekly its requirements for gas and purchased power for the next [redacted]. Inputs to the revised forecasts include not only revised load forecasts (updated semi-annually), but also updated future prices for gas and power, scheduled outages for APS generating units, and operating characteristics of APS's generating units, for example. APS also re-optimizes the mix between gas and power purchases with each update. Some trading of forward "positions" in gas and power may occur in response to shifts in the balance between them. The Company reports that the [redacted] percent hedged is typically [redacted] percent gas, and [redacted] percent purchased power, but this ratio can vary. Hedging at less than 100 percent prevents buying too much energy, with consequent extra costs.

APS does make minor adjustments in response to periodic re-optimization, but does not follow the practice of actively trading its hedges. In other words, once a hedge has been put in place, *i.e.*, once a forward contract, a futures contract or a swap has been bought, it is held to maturity, rather than being bought or sold in response to changes in market prices. The hedging programs of other major natural gas users sometimes allow for "secondary" transactions, in which hedged positions are further traded in an effort to reduce costs. APS views this type of activity as speculation, in that entering such trades requires acting on expectations regarding market direction. The Company has consistently taken a strong position against speculation.

3. Qualifications of Company Personnel

APS M&T has an authorized complement of 70 people and an actual staffing level of 59. They conduct a number of activities other than those associated with the hedging program:

- Nomination of all gas pipeline capacity
- Dispatch of all generating plants and power-purchase contracts
- Arrangement of all off-system sales of electricity and any releases of unused gas transmission capacity
- Conduct of PWCC's remaining non-utility wholesale-market activities
- Monitoring compliance with certain risk-management guidelines
- Development and administration of the Company's natural-gas and purchased-power contracts
- Billing for any gas or power sales
- Payment authorization for natural gas and power purchases.

Most APS M&T personnel are long-time APS employees. Nearly all traders have long experience in power-plant operations. The Vice President, APS M&T was Supervisor of Generation Operations before transferring to Bulk Power Marketing. Most APS M&T employees joined the department (or a predecessor organization) when it was started. The exception is the department's Director of Risk Management, who has a background in trading and risk management in the petroleum industry. He entered power trading with another company, and joined APS M&T in 1999.

The Director of the Company's Energy Risk Management Department, which is organizationally outside of APS M&T, is also a long-time APS employee. He has been involved with APS's energy-trading and risk-management activity for almost the entire time that it has been in existence.

The Company complemented its internal energy trading experience when it initially set up the marketing and trading function. Specialists from the capital markets industry were brought in for that task. The guidelines, procedures, and other structures that those specialists developed remain still largely in place today. All aspects of APS's marketing and trading operation are highly structured, and have been so since the creation of the marketing and trading function.

APS's Vice President, Generation & Transmission (now President of the Company) originally established the marketing and trading operation. He supervised it until early 2003, when that role moved to the Chief Financial Officer ("CFO"). The CFO came to APS from a utility system in the Midwest, where he had started and managed a marketing and trading function.

4. Transaction-tracking Capabilities

The internally developed *TranZ* system tracks M&T activity. APS states that:

> *TRANZ ... provides customized functionality for transaction capture, confirmation, scheduling/operations, valuation, credit and market risk measurement, invoicing, and for reporting ... physical and financial electricity and natural gas transacting activities.*

The system includes the following components:

- *TranZSCHED*: trade capture and delivery system for power, both long-term and real-time transactions;
- *TranZGAS*: trade capture and delivery for natural gas;
- *TranZEVAL*: hourly dispatch module, based on operating-cost and heat-rate characteristics of generating units;
- *TranZVIEWER*: detailed historical data on realized results;
- *TranZMTM*: mark-to-market calculation derived from relevant deal terms in trade capture, and from market prices obtained and calculated according to procedures and stored in the database (TranZDATAMART);
- *TranZINVOICE*: preparation of invoices and data for reports to accounting and treasury departments, using verified values from VIEWER;
- *TranZVALIDATION*: Independent System Operator settlement validation program, which interfaces with the ISO to validate settlement figures based on trading activity recorded in SCHED.

TranZ categorizes the transactions it includes into a book structure, which provides for segregation by trading entity and by commodity. The entities include:

- *System*: APS's utility activities, including purchases and sales of gas and electricity (including jurisdictional off-system sales), and emissions allowances
- *Merchant*: (no longer reflect any activity) these books tracked transactions including sales of power and capacity from the Redhawk merchant plants and the Silverhawk plant, and purchases of fuel for those plants, prior to the change in status of the Redhawk units and the sale of the Silverhawk plant
- *Trading*: APS's non-utility wholesale transactions, including supplying power to retail affiliate APSES, and supplying power under several contracts entered into during the Merchant Period (between the 1999 and 2003 rate cases); most of this activity is in three contracts, with Citizens/UniSource, Tohono Oodham and the City of Williams, AZ.
- *Retail*: transactions supporting Texas and California electricity and natural gas retailing.

Traders primarily conclude transactions: on an electronic trading platform or by phone (on a recorded line). APS uses the Intercontinental Exchange ("ICE") trading platform. Each trader enters transactions on a trade ticket or deal log as they are concluded, and those transactions are entered into TranZ by the end of each day. APS's "middle office" compares each trader's transactions to confirmations for the same transactions that are returned by each counterparty, generally via facsimile or e-mail.

5. Policies and Procedures

APS has extensively documented policies and procedures governing its hedging activity. Principal documents include the following:

- *PWCC Energy Risk Management Guidelines*: This document describes the Company's philosophy and objectives for its energy risk management program, and describes the organization and processes that govern the program. These guidelines are updated annually, and each APS M&T and APSES employee must annually confirm reading them, and agreeing to comply with them.
- *Energy Risk Management Procedures*: This document describes the procedures used by the Company's Energy Risk Management ("ERM") department to identify, measure, monitor and report on the major risks that the Company faces in conducting energy trading activities. ERM is independent of APS M&T, and provides a monthly report to the Company's Energy Risk Management Committee.
- *Energy Risk Management Model Documentation*: This document describes the computer models and data used to quantify and manage market and credit risks incurred in conducting energy-trading activities. It was prepared, and is updated annually by the Company's ERM department.
- *Price Data System Users Guide*: A contractor developed the Price Data System ("PDS") for APS, to automate the process of gathering (and validating) data required for the computations involved in assessing the Company's exposure to market risks. The PDS gathers raw price data, refines it and loads it into the TranZDATAMART. This guide (manual) assists users in operating the system.
- *Counterparty Credit Review Preparation Guide*: A users' guide for evaluating counter-party credit. The ERM department developed and annually updates this guide.

The Company also actively administers its policies and procedures. APS M&T has an internal compliance-management function, which reports to a System Hedge Oversight Committee. That committee is composed of the parent company CFO, APS M&T's Vice President, the Director of Risk Management, and the Portfolio Manager (Regulated). Its functions are to review the status of the Company's hedge positions, to consider and discuss general market conditions, and to review potential modifications of the System Hedge Strategy if warranted.

The Company's ERM department resides organizationally outside APS M&T. It reports to a different officer. ERM provides the "middle office" function for the Company's trading activity, and monitors counter-party (credit) risk and market risk. The industry uses the term "middle office" to refer to the energy-trading organization whose responsibility is to assure that trading activity is entered into the organization's transaction-tracking system in a timely manner, and to verify trades with counter-parties. ERM provides monthly compliance reports to the parent company's Energy Risk Management Committee. The committee considers the overall risk position, ERM's monthly compliance report, and the nature, status, and remedy for any policy or procedure violations or exceptions. The committee is composed of the following:

- The parent company's Executive Vice President and Chief Financial Officer

- The parent's Vice President, General Counsel and Secretary
- APS's Vice President, Planning
- The parent company's Audit Services Director
- APS's Director, ERM
- APS's Vice President and Controller
- APS's Director, Tax Services
- The Vice President, APS M&T
- The Executive Vice President, APS Generation
- APS's Vice President/Treasurer.

6. Utility and Non-Utility Activities

APS M&T provides products and services in two distinct businesses:

- Buying (and hedging) the utility company's short- to medium-term requirements for natural gas and purchased power, optimizing the utility's contracted gas transportation capacity, and conducting the utility's off-system sales of electric power.
- Wholesale trading in support of PWCC's remaining merchant activities, including optimizing some gas transportation capacity acquired during the *Merchant Period.*

The non-utility trading business is substantial. The following table presents some comparisons between the utility and non-utility wholesale businesses.

Table V.1 Comparative Utility/Non-Utility Statistics ($MM)

	2004		2005	
	Utility	**Other**	**Utility**	**Other**
Operating revenues	2,035	401	2,237	352
Fuel/Purchased power expense	567	321	595	293
Total assets	8,674	746	9,732	1,070

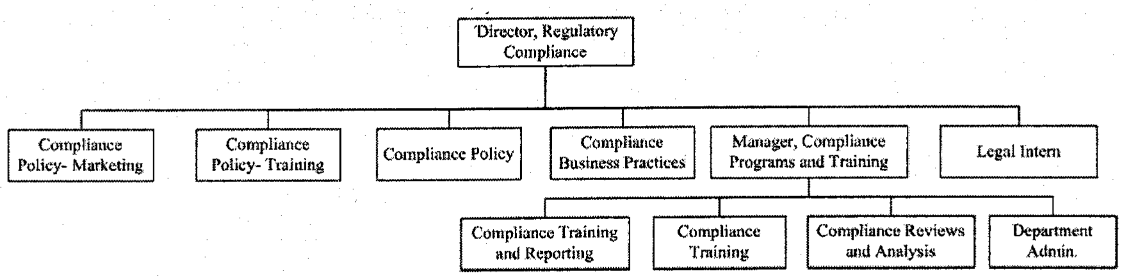
Using the same entity to conduct both businesses when a utility is involved creates special risks. The natures of the two businesses are different. Nevertheless, many activities to conduct them (*e.g.*, buying and selling power, hedging natural gas prices, selling natural gas transportation capacity into secondary markets) are the same. Moreover, many of the counter-parties with whom these transactions are conducted are also the same. Finally, the presence of an adjustment clause at the utility may create an incentive to move individual transactions between the two businesses. Higher-margin transactions could be moved to the wholesale trading business, where the parent company and its stockholders will realize all of the benefits of those transactions, and lower-margin ones to the utility, where the PSA mechanism mitigates impacts to stockholders.

The Company has addressed these risks. First, in response to an audit by the FERC's Office of Market Oversight and Investigations,[2] the Company organized an internal compliance function.

[2] The report from this audit was approved by the FERC in "Order Approving Audit Report and Directing Compliance Actions", issued December 16, 2004, in U. S. Federal Energy Regulatory Commission Docket No. PA04-11-000, *Arizona Public Service Company.*

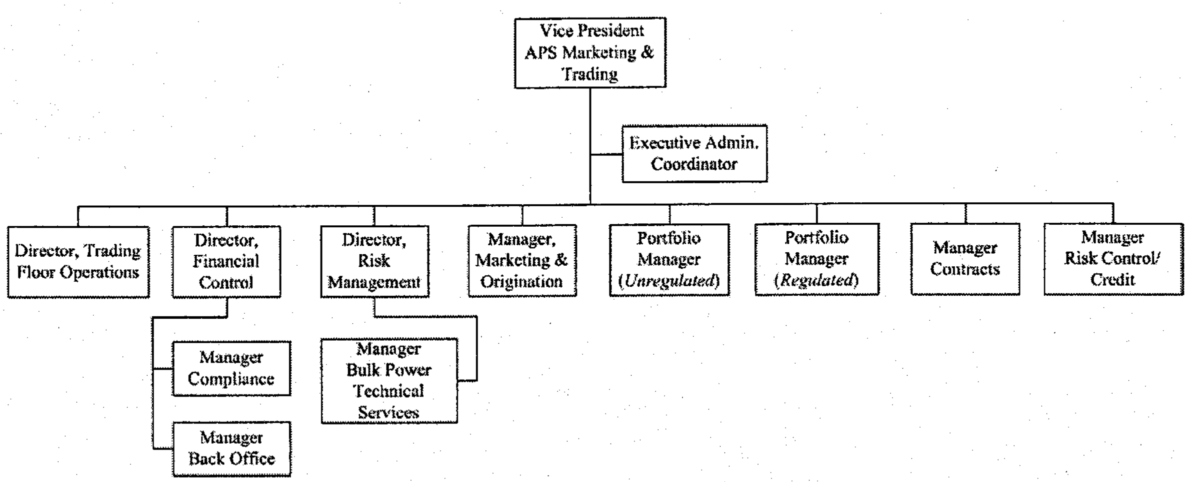
The Regulatory Compliance department conducts compliance programs for FERC and ACC requirements. The department reports to the Executive Vice President for Customer Service and Regulatory Affairs. The next table shows the department's organization chart.

Table V.2 APS Regulatory Compliance Department



Relationships between the Company's utility and non-utility activities are the focus of the ACC compliance effort. The Company reports that it has been discussing these relationships with the ACC Staff for some time. Hearings on these relationships and related matters concluded in November 2005, and the Company was awaiting a final order in the proceeding as this report was written.[3] APS M&T uses separate traders to conduct its regulated and non-utility businesses, although both are located on the same trading floor. The organization chart for APS M&T below shows how the Company has segregated the non-utility business from the utility business.

Table V.3 APS Marketing & Trading Department



All non-utility traders, except the real-time traders, report to the Portfolio Manager (Unregulated). Utility traders report to the Portfolio Manager (Regulated). Utility and non-utility real-time traders report to the Director, Trading Floor Operations because of their singular focus on operations and reliability. Those reporting to the Director, Trading Floor Operations include:

- System Native Load

[3] That order came on June 5, 2006. It requires the filing of an amended code of conduct and supporting policies and procedures to conform to the order. APS recently reported that these documents remain under discussion with Commission Staff.

    - BOM Senior Trader
    - Day-Ahead Senior Short Term Traders
    - Day-Ahead Gas Trader
    - Senior Real Time Traders
- Power Marketing Schedulers
- Merchant Real Time Traders.

Liberty conducted work observations and interviews on the APS M&T's trading floor. Liberty observed that the traders for the utility and non-utility businesses were physically segregated, with the exception of the real-time traders. For reasons of reliability maintenance, the real-time traders for the utility and non-utility businesses sit at adjoining desks. The role of the real-time traders in reliability maintenance requires considerable infrastructure: special communications systems, special computers, special systems for electrical power, etc. Moreover, both real-time desks must be staffed continuously: 24 hours per day, 365 days per year.

All traders use a deal log to enter their trades as they are made. The real-time traders dispatch generating units and other sources of power on a real-time basis, and use their deal logs to record what they have done. The day-ahead traders line up sources of fuel and power for the next day, in time for nomination and scheduling deadlines. The trading floor's schedulers perform the scheduling function for both the utility and non-utility businesses, as they are providing information to control area operators that is generally not interchangeable between the two businesses. For transactions beyond the next day, the traders time-stamp their deal logs as agreement is reached on transactions. The trader or an administrative assistant then enters each transaction into TranZ by the end of each day. As noted earlier, APS's ERM department verifies each transaction with each counter-party by comparing the TranZ entry with confirmation received from the counter-party.

C. Conclusions

1. APS has designed and operates a sound hedging program.

The Company's Energy Risk Management Guidelines and Procedures and its administration of its risk-management program are as strong as any that Liberty has examined. An outside expert reviewed the fuel and purchased-power hedging program during [redacted]. The consultant found that [redacted]. Liberty's review confirmed this assessment.

Liberty found the capabilities of the systems and staff involved in hedging to be strengths. All persons interviewed demonstrated job experience and proficiency, and familiarity with program aspects and job functions related to their direct roles. All support systems are also strong.

Increased market volatility, however, underscores need for strong communication and agreement with regulators about hedging program goals. APS has given internal thought to the matter; what is less clear is the position of customers and of the Commission. Other objectives are possible; the Company should address them with its customers and regulators.

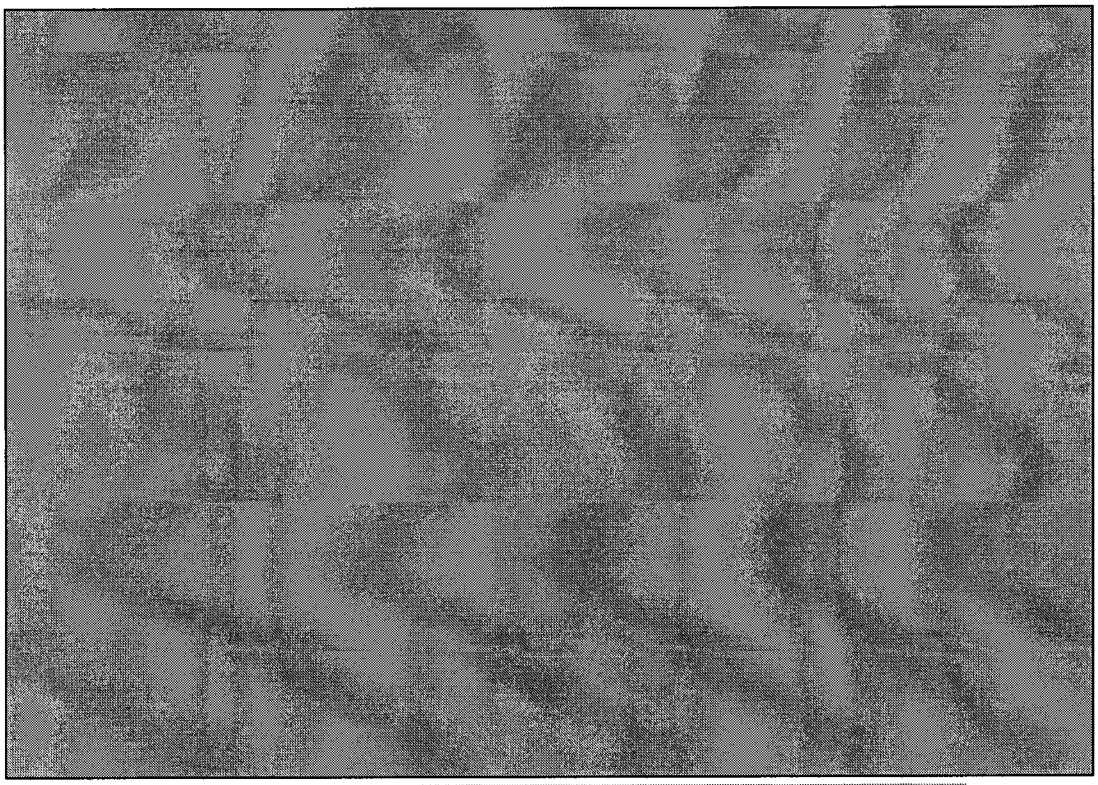
2. The Company's program has been successful in meeting its primary objective.

The following charts estimate the impact of the APS hedging program on fuel and purchased-power costs for calendar 2005 and 2006. The charts show total annual fuel and purchased-power costs would have been on each day plotted. One curve tracks what costs would have been had APS needed to buy fuel and power on the open market. The other (lower) curve shows changes in costs from applying owned hedges. For example, if the Company were to have purchased its entire requirements for fuel and purchased power for the year 2006 on one day in late September of 2005, the total cost would have been about $[redacted]. Applying the hedges that were in place on that day would have brought that total cost down to about $[redacted]. The charts make clear that the hedges have had a significant stabilizing effect on costs for those periods.

Figure V.4 APS Hedged System Costs

ENTIRE FOLLOWING TWO CHARTS ARE CONFIDENTIAL

[redacted]



ENTIRE PRECEDING TWO CHARTS ARE CONFIDENTIAL

3. The Company's hedging program will, however, prevent costs from falling. *(Recommendation #1)*

A consequence of the Company's focus on stability in its fuel costs is that those costs will not decline rapidly if market prices go down. The hedged positions that are today preventing the Company's costs from rising will prevent them from falling if market prices go down.

APS recognizes this possibility, and is concerned about it. The Company has tried to prepare stakeholders for this possibility, but Liberty believes that the matter deserves more extended discussion. That discussion should focus specifically on whether there are effective and acceptable strategies for allowing customers or particular groups of them to benefit more quickly if energy prices decline.

4. The segregation of utility and non-utility activities is not as complete as it should be. *(Recommendation #2)*

With the resolution of the Company's 2003 Rate Case, APS M&T personnel speak of "new clarity about the unit's identity and mission". The Company characterized its non-utility activities as "vestiges" of the "Merchant Period," and offered its expectation that they would disappear when the last of the full-requirements contracts expires in May 2008. Company representatives observe, however, that they have yet to advise the Commission formally of its intentions in this matter. Liberty's concerns about continuation of non-utility trading include a number of issues.

Credit Support: After a period of time trading as Pinnacle West Capital Corporation for its non-utility wholesale trading activities, the Company has now gone back to trading as Arizona Public Service Company. As the responsible party, the utility is providing credit support to the wholesale trading activity, unless specific actions are taken to prevent that result. Wholesale trading involves considerably greater risk than does the utility business. Consequently, a utility company that backs a wholesale trading operation, all other things equal, will have a lower-quality credit than one that does not. Thus, allowing wholesale trading activity to be conducted in the name of Arizona Public Service Company may hurt APS's credit, and also represents a value transfer from the utility to affiliate(s).

Physical Separation of Traders: APS observed that the ACC Staff has expressed comfort with the "separate traders, same trading floor" resolution of potential conflicts of interest arising from simultaneous conduct of two sets of marketing and trading activities: one for the regulated utility and another for the non-utility wholesale trading activity. As indicated by the organization chart presented above, the traders have indeed been separated organizationally. Moreover, Liberty's site visit revealed that the regulated and unregulated traders are also physically segregated on the trading floor, except for the real-time traders. As noted earlier, because of infrastructure requirements necessitated by maintenance of reliability, the real-time traders for the utility and non-utility activities continue to sit next to each other.

Risk Metrics for Utility Activities: PWCC is careful about measuring and managing the risks associated with its non-utility trading operations. Risk metrics, such as Value at Risk ("VaR") and Capital at Risk ("CaR") have been calibrated to the scope of activity that PWCC is comfortable with conducting. Changing any of those limits requires approval by the parent company's board of directors.

Risk metrics for the Company's utility activities are less well developed. Credit limits for individual counter-parties, for example, are computed on the basis of APS M&T's overall assessments of each party's creditworthiness. Each limit is then shared between PWCC's utility and non-utility trading activities as their transactions require. If it were to happen that non-utility trading used up the credit limits assigned to the most creditworthy counter-parties, then the utility would be obliged to trade with less credit-worthy ones. Alternatively, the utility might trade less, with consequent loss to its customers. Other risk metrics remain to be developed for the utility.[4]

Agenda for Internal Audit: When traders for the utility and non-utility parts of PWCC's business are transacting in the same commodities or instruments, at the same locations or the same exchanges, and at the same time, there is potential for error, particularly if the names of the two entities are similar. There is also potential for deliberate misassignment. With independent confirmation by the middle office, these risks can be reduced, but not eliminated.

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[4] PWCC's Energy Risk Management Guidelines, dated May 2005 (and furnished to Liberty as part of the Company's response to DR No. STF 1.9), states (at p. 7) that "Risk metrics for the Regulated activities are under development."

Liberty reviewed the Company's recent internal and external audits related to fuel procurement, power procurement and price risk management. This review revealed that nine of them addressed various topics within the marketing and trading function, but none dealt with the utility/ non-utility split. Going forward, it is an area that requires audit attention as long as the two entities continue to trade in parallel.

D. Recommendations

1. Engage stakeholders in a discussion of hedging program objectives. *(Conclusion #3)*

The preferred approach to setting the objectives of the Company's hedging program would be to work with customers, other stakeholders, and the Commission in a process that includes dialogue and consensus building, where possible. APS should establish ways to explore the needs, expectations, concerns, values and preferences of its customer groups, seek to rationalize them, if possible, and then report on them to the Commission.

Broadly speaking, energy users hedge in pursuit of two objectives: stabilizing prices or lowering prices. It is frequently believed that commercial and industrial customers generally prefer price stability over obtaining the lowest possible price, where there is tension between the two results. Price stability facilitates their budgeting for their costs of doing business, and may help them determine how to price their own products and services. In contrast, it is frequently asserted that residential customers prefer the lowest possible price. Most residential customers, on the other hand, understand the need for protection from sudden or sharp price increases (price "spikes"), but they may prefer to gain the benefit of lower prices as soon as that benefit can be made available.

Pursuit of hedging objectives other than price stability would involve different strategies and different instruments. The different strategies would have different risks, and the different instruments would have different costs. Making a different and potentially more complex set of options available would take a well-designed communications program addressing these matters with customers in a manner that explains the trade-offs in ways that could be understood by different customer groups. Customers' reactions to these trade-offs can and should be made part of the Company's report to the Commission in this area.

Obtaining input from commercial and industrial customers should be relatively straightforward; conducting a "dialogue" with residential customers may prove more difficult. Arizona's Residential Utility Consumer Office ("RUCO") is one potential resource that is knowledgeable about the utility business. Some utilities have also used customer focus groups to explore customer attitudes in some detail.

Liberty recommends that efforts to determine customer preferences in this area begin soon, and take place over a defined time interval. Liberty recommends the next six months. Allowing some time for synthesizing various inputs and preparing a report, Liberty recommends that the Company present a report to the Commission on customer preferences for hedging, and adjustments (if any) to the Company's program in light of these preferences, nine months after acceptance of this recommendation.

2. Report to the Commission on the future plans for non-utility activities. *(Conclusion #4)*

If the Company's non-utility trading activities are to continue, it has work to do in further segregating those activities from similar activities at the utility. The Commission needs a definitive statement of the Company's intentions in this area. If non-utility trading activities are to continue, the Company should also present a plan for the further segregation of those activities. The plan should address at least the following areas:

- Credit support: How will the Company keep the credit requirements of the wholesale trading operation from affecting the conduct and costs of the utility business?
- Physical separation of traders: The Company maintains a "hot back-up" facility for its communications and control systems, complete with its own power supply, in Deer Valley. This facility is essential to continued operation of the Company's control systems in the event of loss of power to the downtown location for any reason. As the back-up facility is completely equipped but rarely used, would it provide a suitable location for non-utility trading operations?
- Risk metrics for the utility: As an asset-based business, the utility has risks that are different from the trading business. What metrics are appropriate to those risks, and what limits should apply?

VI. Forecasting and Modeling

A. Scope

Liberty reviewed how the Company develops fuel and purchased power budgets by use of simulation models for both long and short-term markets, and analyzed the effectiveness in achieving least-cost dispatch.

B. Findings

The multitude of capacity and energy resources available in today's electric power industry requires the development of accurate fuel budgets and the use of computer simulation models. Effective forecasting requires a significant and detailed information about many aspects of each individual generating unit, including:

- Nameplate capacity
- High operating limit
- Minimum operating limit
- Mid-point control points
- Heat rates for each operating point
- Full heat rate curve
- Ramp rates
- Minimum run times
- Minimum outage times
- Maintenance schedules
- Forced outage rates
- Primary and secondary fuels
- Emission limitations.

Information on fuel supply, fuel prices, heat rate content, minimum fuel inventory levels, monthly peaks, monthly energy sales, transmission path limitations, load shapes, and system reserve requirements must all be gathered, analyzed and input into the models.

Developing an effective database requires coordination of several utility functions and information from other utilities or the independent system operator. The database requires constant updating as resources and load changes. These requirements apply for the simulation models used to develop the budget for the PSA; they apply equally to the model used to develop the dispatch list for the day-ahead traders.

1. Model Selection

The principal model used in the determination of near term fuel requirements is a probabilistic, production cost model, known by the trade name *RTSim* (Real Time Simulation). RTSim is a licensed, proprietary product of Simtec, Inc. of Madison, Wisconsin. Simtec has a wide variety of clients across the country. APS chose it because of its accuracy and ease of use.

The model employs unit commitment and dispatch logic to simulate optimal daily system operations, and to facilitate the determination of the optimal mix of fuel burns. The goal is to develop the lowest cost of power production. Inputs to the model include an hourly system load forecast, operating characteristics (*e.g.*, heat rates, capacities, minimum load levels, start-up costs) for all resources (*e.g.*, gas, coal, nuclear, wind) employed in the system or planned for future operation, fuel prices and market prices for power purchases (*e.g.*, standard block products, options, day-ahead and hourly products).

Model outputs include cost projections, projected individual generating unit energy production, power purchases required to serve forecasted load, and any economic sale opportunities. The energy production projections attempt to establish the quantities of gas, coal, or nuclear fuel requirements for the company.

APS first acquired RTSim under a test agreement in mid-1998. APS tested RTSim for almost a year, and performed several months of parallel processing with the then-existing production cost model known as *RES*. APS had developed RES in house many years before, custom designing it to capture the unique operations of the APS system under the traditional utility operations of the time. During testing and benchmarking, APS requested a number of enhancements to the model. APS acquired the non-test version of the model, incorporating the enhancements, in January 1999. APS stopped running RES and began to use the new model exclusively to perform the Company's operating studies in May 1999.

APS addresses daily unit dispatch by daily runs of a resource commitment model that optimizes unit commitment. This short-term model, *Resource Commitment System*, operates as a deterministic model that calculates dispatch order. APS purchased the original software platform for this task from Staggs Software Co. APS uses the same data to maintain the RTSim database and Resource Commitment System. Speed of calculations represents the primary difference between them. Resource Commitment System only calculates dispatch order; therefore it can calculate faster because it does not require the extensive data base that RTSim needs.

Most of the APS RTSim users have prior experience with other production cost models. All personnel responsible for executing the model have received the one-week intensive training course offered by RTSim's developer, Simtec, Inc. The one-week course enables experienced model users to understand the unique features of RTSim as compared to other models. New users to the model acquire additional on-the-job training under the mentoring of the experienced operational planners, who have had years of prior experience using production cost models, and who have a sound understanding of system operations. Depending upon their background, new users typically spend a year or two working under the guidance of these more experienced users before they take responsibility for independent work.

The APS M&T Department has four individuals trained to execute the model. The Forecast Department has two individuals trained to execute the model.

2. Data Accuracy

The Company uses several management processes to ensure the accuracy of RTSim input data:

- *Data Control*: APS uses a formal input approval process combined with a secure database that houses all official data and assumptions underlying the execution of RTSim. APS controls access to this database, which it limits to personnel who must enter data into the database or who have a need to use the data. Formal processes exist for the collection of data and for approval of data entry. The Vice President of Fossil Generation, the Executive Vice President, APS Generation, and the Vice President of Marketing and Trading approve all data that their own organizations enter into the data base.

- *Information Updating*: inputs updates take place formally at least twice each year: in the fall, during budget development and in the spring during Long Range Forecast development. Between these semi-annual activities, adjustments get made as changes to assumptions and data occur in order to assure that operating studies continue to use the most current data and assumptions.
- *Forecast Benchmarking*: at the time of each official forecast update, APS compares the results to a previous case to ensure that the changes show consistency with those anticipated. Detailed analyses are occasionally required to confirm the validity of the updated results. In cases where these comparisons reveal inappropriate or inaccurate inputs in the model, the inputs are corrected and the model is re-run to produce the correct results.
- *Operations Benchmarking*: APS performs monthly, detailed comparisons of actual power plant operations and fuel and purchased power expense results with budgeted amounts. APS makes these comparisons at an hourly level of detail to account for such factors as energy load variations, dispatch prices for natural gas and power, power plant availability, and dispatch operations. Findings from these comparisons may result in changes to the modeling of fuel and purchased power volumes and expenses if warranted.

APS continuously maintains the database because it runs the model on a weekly schedule to meet term-trader operational needs. APS takes care to maintain accurate maintenance schedules and fuel forecasts. In addition, studies can also be run as needed to assess the economic impact of changes in power plant operations and/or to assess specific purchase or sale opportunities.

3. Use of Model Outputs

APS runs RTSim in an operational role to establish the volume of power and natural gas requirements, to evaluate power plant maintenance plans, and to evaluate sales and purchase opportunities. The Company formally updates the model twice per year as part of the fuel and purchase power budgeting process. It establishes cost and volume projections for the coming and subsequent years. Because of the different nature of gas, coal and nuclear fuel markets, the fuel projections are provided to different departments. The APS system term trading group has responsibility for managing the company's gas procurement requirements in accordance with the company's hedging plan.

APS uses ad hoc operational studies to assess the economic impact of changes in power plant operations and to assess specific purchase or sale opportunities. Additionally, RTSim runs periodically throughout the year to provide updated fuel and purchased power expense forecasts for financial model projections. These projections include the development of the Company's annual budget and the long range forecast, but may include other analyses as well.

Finally, APS M&T uses the model continuously. This group manages the procurement of power purchases (together with natural gas) using weekly RTSim volume and price projections (known as the *Balance Report*) to trade with other market participants.

4. Production Modeling and the PSA

APS used RTSim to develop its 2003 Base Fuel Rate of 2.0743¢/kWh to establish fuel and purchased power expense levels. For that 2003 Base Fuel Rate, APS normalized for fuel and power prices, customer levels and energy usage, power plant availability and other factors.

C. Conclusions

1. APS uses sufficiently accurate modeling to predict fuel and purchased power volume and cost.

APS continually monitors the accuracy of database inputs, which comprises an important step in assuring the accuracy of its short-term forecasts, given APS's hedging strategy to control gas costs. The Company reports an inaccuracy level of 1 to 2 percent in those forecasts. The models are sufficient for predicting fuel and purchase volume and cost during periods of stable fuel prices and stable loads. As is typical, the accuracy of the model is less predictable in times of unstable costs.

Given that the model output is used to develop the operating plan for the next day, management has the model updated daily and audited weekly for accuracy. As conditions change during "real-time," efforts are made to modify the plan as needed, and new model runs are made. The importance that APS places on the model and its accuracy is reflected in the fact that the manager in charge of running the model is assigned to the Marketing and Trading Department

2. APS has taken appropriate actions to ensure that least cost total dispatch is achieved.

By most metrics of success APS is doing a good job of modeling its fuel and purchased power budget. APS is using tools that are accepted by the industry. The Company took care in benchmarking the model's accuracy for use on its system. APS trains its people well and continually maintains the database (and associated output) with the most up to date information to maintain the accuracy of its forecast. This is all done by management to ensure that least cost total dispatch is achieved.

3. APS uses outside reviews appropriately to improve management and operations.

APS conducted three reviews relevant to forecast accuracy: a term trading audit, a unit dispatch audit, and a power plant operating parameters audit. The first two audits reviewed whether APS had the appropriate tools and training available for their trading personnel to minimize the cost of purchased power. In both cases the audits found that APS [redacted]. The power plant operations performance audit recognized that the [redacted]. The preliminary audit found that [redacted]

APS performed the three reviews at about 10-month intervals, which is sufficient. APS scoped the audits narrowly to address specific actions to improve forecast accuracy, which demonstrates an appropriate commitment to improving operations.

4. APS maintains adequate documentation to support regulatory oversight and review.

The amount of documentation is extensive and thorough. It includes bi-annual fuel budgets, monthly variance reports, weekly balancing reports, and ad-hoc operational studies.

D. Recommendations

Liberty has no recommendations addressing the area of Forecasting and Modeling.

VII. Plant Operations

A. Scope

This chapter of Liberty's report addresses the following topics related to operations of the generating stations at APS:

- APS Dispatch Order and Constraints
- Fossil Unit Availabilities, Capacity Factors, and Heat Rates
- Unit Capital and O&M Expenditures
- Fossil Unit Outage Scheduling
- Economic Evaluations Regarding Fossil Unit Outages
- Outage Scheduling and Interface with the Market
- 2005 Fossil Unit Outages
- Net Replacement Power Costs.

Liberty's audit excluded operations of the Palo Verde Nuclear Plant, which are being addressed in a separate examination.

B. Findings

1. APS Dispatch Order and Constraints

The Phoenix Load Pocket

The greater Phoenix area has been designated the "Phoenix Load Pocket," because sufficient generation within this area must be operated to provide security, voltage control, or spinning reserve for this part of the APS system. Both APS and the Salt River Project ("SRP") serve load in the 11,149MW Phoenix Load Pocket. Total transmission and generation capability for this area amounts to 12,375MW, which provides a reserve margin of 1,226MW. APS's Ocotillo (330MW) and West Phoenix (988MW) generating stations and SRP's Kyrene (520MW), Santan (1200MW), and Aqua Fria (600MW) generating stations lie within the Phoenix Load Pocket. Total generation within the actual Load Pocket amounts to 3,638MW.

In 1999, the Company began to structure its fleet of generating units to operate in a more competitive market regime. After 1999, the Company built Redhawk Units #1 and #2 about 40 miles west of Phoenix, and West Phoenix Unit #5 within the Phoenix Load Pocket. The Company did not build market generation in any other locations. Subsequently, in 2002, the ACC ordered that these former merchant units be brought into rate base. The parties including the other merchant generators reached a settlement agreement, which the Commission approved, effective April 2005.

APS Dispatch Order

The following table illustrates the general order in which APS must dispatch its fleet of generating units. The table includes the former merchant units. The table also illustrates the magnitude of replacement power costs faced by APS. The former merchant units have operated under frequent cycling as part of the APS dispatch regime. That form of operation affects the unit heat rates and capacity factors of the more expensive gas units and the combustion turbines.

Table VII.1 APS Generation Dispatch Order

Unit Type	Accredited MW[5]	Cumulative Total MW	Op. Cost ¢/kWh[6]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

APS expects a summer 2006 system peak load of approximately 7,300MW. The summer peak has been increasing at approximately 300MW per year. Reserve requirements at 15 percent bring total APS requirements to 8,395MW. Minimum load on the APS system is between 2,500MW and 3,000MW. APS uses the Cholla units to follow load at these lighter load levels; SRP uses the Navajo units for that purpose. Both the APS and SRP power systems rotate load-following responsibilities among the units at those stations.

APS must integrate its system power supply contracts into this dispatch order. APS has a long-term 340MW, hourly dispatched, 10,000 BTU/kWh contract with SRP. This capability can be ramped at 110MW/minute, which makes it useful for spinning reserve requirements. APS also has a no-cost 480MW seasonal swap contract with PacificCorp. The contract provides for swaps on a one-for-one MWh basis, with day-ahead scheduling. Energy not used by either party is lost.

The APS dispatch order now includes West Phoenix Unit #5 and Redhawk Units #1 and #2. These large, very efficient gas-fired former merchant generating units have heat rates of approximately 7,400 BTU/kWh. They were originally designed to operate as base load units, but now must run in the intermediate range, and follow load. Their April 2005 introduction into the dispatch order changed the operation of the units above them (*i.e.*, more expensive) in the dispatch order. Thus, these more expensive units now run less often, and run less often at full load. This change adversely affects their performance metrics, which this chapter will discuss subsequently. The impacts affect heat rates, maintenance requirements, and economics.

[redacted]

2. Fossil Unit Availabilities, Capacity Factors, and Heat Rates

Background

Power suppliers measure the performance of generating units in numerous ways over a variety of time periods. Unit Availability Factor ("UAF") serves as a primary measure.[14] A unit is considered to be available for this calculation even if it is running at a reduced output in support of system control, or because of equipment problems. To address this reduced output issue, the industry uses the measurement of the unit Equivalent Availability Factor ("EAF"),[15] which restates the UAF assuming full load operation. Net Capacity Factor ("NCF") serves frequently as a measure of unit output.[16] Some utilities modify this measurement by calculating it for the time period the units were requested to run. This change makes the measurements more comparable to desired performance. The efficiency of the unit is measured by the unit Net Heat Rate.[17]

The values of these measurements can be affected by many factors, which include:

- Frequency and duration of planned maintenance
- Frequency and duration of outages due to equipment failure
- Running a unit to provide spinning reserve or voltage control for the system
- Fuel used and its quality
- Unit design
- Unit placement in the dispatch order
- Equipment selection
- Environmental protection requirements
- Air ambient temperature or relative humidity.

Base Load Plants

Unit efficiency and long-duration of operation are key factors for base-load units. The APS base-load units include five coal units at Four Corners, three coal units at Cholla, and three coal units at SRP's Navajo plant.[18] The next table lists the UAF, EAF, and NCF for those plants. Net MW reflects the APS ownership share. The table also restates each unit's UAF and NCF by deducting

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[14] Availability Factor is an expression in percent of the time (in hours) that a unit was running or ready to run if called upon to do so compared with the time in the period. A unit with a 50 percent annual availability was therefore ready to run for 4,380 hours in that year.

[15] Equivalent Availability Factor is an expression in percent of the equivalent time (in hours) that a unit was running at its full net load or ready to run if called upon to do so compared with the time in the period. A unit with a 50 percent annual availability that ran 50 percent of the time it was available, and ran at 80 percent load for 25 percent of the time it was running would have an Equivalent Availability Factor of 2,190 hours (available, not running), plus 1642.5 hours (running, full load), plus 438 hours (equivalent full load hours of 547.5 hours at 80 percent load) or 4,270.5 hours in that year. That would equate to an Equivalent Availability Factor of 48.75 percent.

[16] Net Capacity Factor is an expression in percent of the net generation (in kWh) that a unit generated compared to the maximum amount of net generation it could have generated during the period. If our example unit had a net output of 100MW, it would have a capacity factor of 164,250MWh plus 43,800MWh compared to the possible 876,000MWh that could have been generated during the year. That Capacity Factor would be 23.8 percent.

[17] Net Heat Rate is an expression of the amount of heat energy put into the unit to get net electrical energy out. Generally, it is expressed as the number of British Thermal Units (unit of heat equaling about 252 calories) of fuel input to the unit to obtain one net kWh of output.

[18] Palo Verde nuclear units have similar desirability, but are not part of this examination.

the time the unit was out of service for planned minor, major, and reliability outages. This restatement of these metrics permits a more direct comparison among the units, by recognizing that not all units underwent maintenance during the year. The performance measurements for the base-loaded coal plants were not affected by the introduction of the former merchant plants into the APS dispatch in April 2005 because the operational costs of the merchant plants were higher.

Table VII.2 Major Unit 2005 Actual and Restated Measurements (%)

Unit Name	Net MW	2005 UAF	2005 EAF	2005 NCF	Planned Outage Days/Type	2005 UAF Restated	2005 NCF Restated
Four Corners #1	170	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Four Corners #2	170	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Four Corners #3	220	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Four Corners #4	113	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Four Corners #5	113	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cholla #1	110	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cholla #2	260	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cholla #3	260	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Navajo #1	105	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Navajo #2	105	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Navajo #3	105	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The table illustrates that EAF is lower than UAF by [redacted] to [redacted] percent. These lower values are expected to reflect hours of reduced operation due to equipment problems or the necessity to match minimum loads on the system. APS has 1,164MW of nuclear generation and 1,731MW of base-loaded coal generation, totaling 2,895MW. Minimum system load in the 2,500MW range sometimes requires reduction in coal generation. Given the load conditions that APS faces, the observed reduction in EAF is expected.

Liberty restated the UAF and NCF in the table by deducting the hours when the units were in major, minor, or reliability outages for planned maintenance. All unplanned maintenance, unit reduction, and forced outage time remains in the calculations. From the restated data, UAFs for the time where the units were expected to be available ranged from approximately [redacted] to [redacted] percent. NCFs for the time where the units were expected to be running ranged from approximately [redacted] to [redacted] percent. SRP uses one unit at the Navajo station to follow load during light periods on its system. In 2005, Navajo Unit #3 served in this capacity and accounts for an approximate [redacted] percent reduction in NCF. Liberty found the restated values to be within the range it would expect for these base-loaded coal plants.

The 2005 heat rates at the Four Corners Plant showed an approximate [redacted] BTU/kWh improvement over 2004. Fluctuation in heat rate value can result from the number of startups and other operating conditions. Liberty believes, however, that the improvement obtained in 2005 resulted from better plant operations. Cholla Units #1 and #3 heat rates are approximately [redacted] BTU/kWh, and have remained in a fairly close range around this value for a number of years. The Cholla Unit #2 heat rate dropped from approximately [redacted] BTU/kWh to [redacted] BTU/kWh in 2005. Liberty believes that this improvement resulted from the replacement of the low-pressure turbine in 2005. The 2005 Navajo Units #1, #2, and #3 heat rates of approximately [redacted] BTU/kWh showed an approximate [redacted] BTU/kWh improvement over 2004. Liberty believes that these improvements are due to better plant operations.

Large, Efficient Gas Units

Performance metrics for the gas plants and the combustion turbines were adversely affected by introduction of the former merchant plants into the APS dispatch order in April 2005. The large former merchant units ran at a [redacted] to [redacted] percent NCF for 2005. These measures include the first three months of the year, during which they remained merchant plants and appeared to be running at lower NCFs. Liberty considers it likely, therefore, that NCFs for these plants will rise in 2006. These large units run after the base-loaded coal units in the dispatch order. Accordingly, APS operates them in an intermediate dispatch position, and must follow load variations. The [redacted] BTU/kWh range heat rates of these large units push the less efficient gas units[19] higher on the dispatch curve. UAFs remained high at [redacted] to [redacted] percent for the large efficient gas units. The West Phoenix Unit #5 location within the Phoenix Load Pocket has also affected its operation. The unpredictable operating conditions necessary to support system control can have adverse impacts on the performance metrics of the unit. Overall, Liberty found the performance metrics of the former merchant units to fall within an expected range, given dispatch conditions.

Less Efficient Gas Units

Movement upwards on the dispatch curve results in lower NCFs for less efficient units, because APS does not call upon them as often. Higher heat rates result because the units must operate at reduced loads more frequently. UAFs and EAFs, however, should remain relatively unchanged. Review of the APS data shows that the less efficient APS unit performance measurements show expected results. West Phoenix Units #1 - #4 and the units at Ocotillo can also be affected by their location within the Phoenix Load Pocket. Liberty found that the performance metrics of these less efficient units were consistent with their movement in the APS dispatch order.

3. Unit Capital and O&M Expenditures

The following table shows major capital expenditures at APS generating stations. The number in parentheses represents the number of major unit maintenance outages taken in that calendar year.

Table VII.3 Major Capital Expenditures[20] at APS Generating Stations

Power Plant	Units	2001	2002	2003	2004	2005
Four Corners	5	9.7 (1)	25.9 (2)	19.7 (1)	25.6 (2)	18.2 (1)
Cholla	3	5.9 (0)	9.7 (0)	13.2 (0)	7.1 (0)	15.0 (1)
West Phoenix	5	8.9 (2)	- (1)	- (2)	- (1)	5.9 (1)
Redhawk	2	*	1.2 (1)	- (0)	- (0)	1.4 (0)
Ocotillo	2	- (0)	- (0)	- (0)	- (0)	- (0)
Saguaro	2	1.7 (0)	2.6 (0)	- (0)	- (0)	- (0)

Millions of dollars * - Units not in operation.

[19] West Phoenix #1 - #4, Ocotillo #1-#2, Saguaro #1-#2, Sundance #1-#10, and all combustion turbines.

[20] Liberty defined a major capital expenditure as a project that APS expended in excess of $1 million for illustrative purposes. Many smaller projects aggregate to significantly greater capital expenditures and a small ownership interest in a plant can mask a major project.

The table shows an expected correlation between capital expenditures and major unit outages, because larger, more capital intensive projects occur generally during major outages. The table also shows that APS has continued to make significant capital expenditures at the coal plants, even during years without major outages. This result is also consistent with general experience. The importance of the coal units in keeping electricity costs low makes them important priorities when capital expenditures are set. Performance metrics indicate that the Cholla and Four Corners units have been running well. Liberty saw no indicators of insufficient attention to equipment upgrades and modifications. The Navajo units have also been running well.

The following table summarizes O&M expenditures at the APS fossil stations. The number in parentheses represents the number of major unit maintenance outages taken in that calendar year.

Table VII.4 O&M Expenditures at APS Generating Stations

Plant	Units	2001	2002	2003	2004	2005
Four Corners	5	38.2 (1)	41.6 (2)	43.0 (1)	43.5 (2)	47.6 (1)
Cholla	3	33.0 (0)	28.8 (0)	32.9 (0)	33.3 (0)	37.8 (1)
Navajo	3	11.2 (0)	9.9 (0)	13.8 (1)	15.5 (1)	15.0 (1)
West Phoenix	5	10.1 (2)	7.3 (1)	10.1 (2)	12.2 (1)	13.7 (1)
Redhawk	2	*	4.4 (1)	13.6 (0)	14.1 (0)	18.0 (0)
Ocotillo	2	5.0 (0)	5.8 (0)	3.8 (0)	4.4 (0)	4.6 (0)
Saguaro	2	4.6 (0)	4.1 (0)	4.3 (0)	3.9 (0)	3.3 (0)

Millions of dollars
* - Units not in operation.

The table shows that APS has been making consistent O&M expenditures at its major plants. There has actually been a marked increase in O&M expenditures at APS coal plants and the former merchant plants. Liberty found O&M expenditure patterns to be consistent with system operational requirements.

4. Fossil Unit Outage Scheduling

Four Corners Units #1 and #2 – 170MW Coal (each)
These units experience scheduled, [redacted]-day major maintenance outages (boiler, total turbine, and all components except generator) every [redacted] years, except that scheduled generator maintenance is on a [redacted]-year cycle. No reliability outages have been taken recently, but APS now plans to take such outages at the [redacted] -month time point between the major outages, in order to reduce the [redacted] to [redacted] forced outage days experienced on average.

Four Corners Unit #3 – 220MW Coal
The maintenance schedule for this unit is the same as that for Units #1 and #2.

Four Corners Units #4 and #5 – 113MW Coal (each)
These units experience scheduled, major [redacted]-day maintenance outages (boiler, total turbine, and all components) every [redacted] years and minor, [redacted]-day maintenance outages (boiler, induced draft fans) in the [redacted] year of the [redacted] -year cycle. APS now takes reliability outages at the [redacted]-month time point between the major and minor outages in order to reduce the [redacted] to [redacted] forced outage days experienced on average.

Cholla Unit #1 – 110MW Coal

This unit experiences scheduled, major [redacted]-day maintenance outages (boiler, total turbine, generator, and all components) outages every [redacted] years and minor, [redacted]-day maintenance outages (boiler, induced draft fans, common scrubber) in the [redacted] and [redacted] years of the [redacted]-year cycle. [redacted]-day reliability outages (directed at the scrubber) are taken at the [redacted]-month time point between the minor and major outages.

Cholla Unit #2 – 260MW Coal

This unit experiences scheduled, major [redacted]-day maintenance outages (boiler, total turbine, generator, and all components) every [redacted] years and minor, [redacted]-day maintenance outages (boiler, induced draft fans, common scrubber, and dust collection) in the third and [redacted] years of the [redacted]-year cycle. [redacted]-day reliability outages (induced draft fans) are taken at the [redacted]-month time point between the minor and major outages. This unit had its high-pressure and intermediate-pressure turbine replaced in 2005.

Cholla Unit #3 – 260MW Coal

This unit experiences scheduled, major [redacted]-day maintenance outages (boiler, total turbine, generator, and all components) every [redacted] years and minor, [redacted]-day maintenance outages (boiler, electrostatic precipitator) in the [redacted] and [redacted] years of the [redacted]-year cycle. No reliability outages are taken because of the difference in pollution control equipment. Unit #2 has a scrubber; Unit #3 does not. The absence of a scrubber reduces maintenance requirements on Unit #3. This unit will have its [redacted].

Navajo Units #1, #2, and #3 – 105MW Coal (each)

These SRP-operated units undergo scheduled, major [redacted]-day maintenance outages (boiler, total turbine, generator, coal handling) every [redacted] years and minor, [redacted]-day maintenance outages (boiler) in the [redacted] year of the [redacted]-year cycle. Liberty does not know if reliability outages occur.

Ocotillo Units #1 and #2 – 110MW Gas (each)

The boilers, turbines, and generators at these units are the same. The boilers are sensitive to thermal cycling. A [redacted]-day reliability outage is taken prior to [redacted] in an effort to maximize generation in that [redacted] period. The turbine-generator is on a [redacted] equivalent factored hour inspection schedule for major inspections.

Saguaro Unit #1 - 110MW Gas and Unit #2 – 100MW Gas

The maintenance schedules for these units are identical to those for Ocotillo.

Redhawk Units #1 and #2 – 492MW Gas (each)

These units have a super-efficient design consisting of two combustion turbines and one steam unit, with design heat rate of approximately 7,000 BTU/kWh. These General Electric Model 7FA units have a triple reheat Heat Recovery Steam Generator ("HRSG") designed for base load operation. Thermal cycling was not designed into these units. In bypass mode, one combustion turbine can run at the 70 percent power level. A [redacted] day reliability outage is taken prior to [redacted] in an effort to [redacted].

Maintenance can be driven by the number of starts or the number of hours operated. If the average of hours per run is greater than [redacted], the unit maintenance is hours driven; otherwise, it is driven by the number of starts. Currently, hours are the controlling maintenance factor for both units. The turbine-generator of the combustion turbine is on a [redacted] factored-fired hour inspection schedule, with each inspection scheduled for [redacted] days. Every [redacted] hours of factored fired operation requires a [redacted]-day combustion turbine hot gas path inspection and includes the minor inspection. The steam unit undergoes a B level inspection (valves, controls) also at this time. Every [redacted] hours of factored fired operation requires a [redacted]-day major outage for the main unit turbine generator (all equipment) and includes the hot gas path and minor inspections.

<u>West Phoenix Units #1, #2, and #3 – 85MW Gas (each)</u>
These units are Stag 100 simple cycle units, with one combustion turbine per steam unit. If no inspections are scheduled, a [redacted]day reliability outage is taken prior to [redacted] in an effort to maximize generation in that [redacted] period. The turbine-generator of the combustion turbine is on an [redacted] factored fired hour inspection schedule, with each inspection scheduled for [redacted] days.[21] Every [redacted] hours of factored fired operation requires a [redacted]-day combustion turbine hot gas path inspection and includes the minor inspection. Every [redacted] hours of factored fired operation requires an [redacted]-day major outage for the main unit turbine generator (all equipment) and includes the hot gas path and minor inspections.

<u>West Phoenix #4 – 117MW Gas</u>
Maintenance can be driven by the number of starts or the number of hours operated. Currently, number of starts controls maintenance for this unit. The turbine-generator of the combustion turbine is on a [redacted] factored fired hour or [redacted] equivalent factored starts inspection schedule, with each inspection scheduled for [redacted] days. Every [redacted] hours of factored fired operation or [redacted] equivalent factored starts requires a [redacted]-day combustion turbine hot gas path inspection and includes the minor inspection. Every [redacted] hours of factor-fired operation or [redacted] equivalent factored starts requires a [redacted]-day major outage for the main unit turbine generator (all equipment) and includes the hot gas path and minor inspections.

<u>West Phoenix #5 – 506MW Gas</u>
Maintenance can be driven by the number of starts or the number of hours operated. Currently, the unit starts drive the maintenance schedule. The turbine-generator of the combustion turbines is on an [redacted] factored fired hour or [redacted] equivalent factored starts inspection schedule, with each inspection scheduled for [redacted] days. Every [redacted] hours of factored-fired operation or [redacted] equivalent factored starts requires a [redacted]-day combustion turbine hot gas path inspection and includes the minor inspection. Every [redacted] hours of factored fired operation or [redacted] equivalent factored starts requires a [redacted]-day major outage for the main unit turbine generator (all equipment) and includes the hot gas path and minor inspections.

[21] The outage times for these units appear long because they are only done on a straight-time basis in the off peak period.

5. Generation Unit Capital Project Planning

Capital project priorities are set on a system-wide basis. APS uses a single-point-of-failure analysis and a centralized database to perform capital project evaluations. APS gives planners direct responsibility for performing assigned analyses. The analysis of potential capital projects considers plant availability, equipment age, and other issues arising from unique plant conditions and emerging industry knowledge and issues. APS uses a 10-year horizon for identifying capital projects at its generating units. The plan and its components undergo annual review and updating. APS uses a simple payback of approximately three to five years (an internal rate of return of 15 percent)[22] as the economic threshold for the evaluation of capital projects.

Plant personnel evaluate smaller potential projects; larger projects are evaluated centrally. The Vice President, Fossil reviews all proposed projects. The Fossil Generation department at APS has developed a two-day course addressing economic evaluations of generating units. APS planners and evaluators from both the central office and from the generating stations attend these courses. APS offers a refresher course as well.

6. Spare Parts for Generating Stations

APS maintains a company-wide materials management system; it tracks warehouse spare-parts inventories at Four Corners, Cholla, Redhawk, and West Phoenix. APS sets inventories on the basis of the criticality of each part, and accounts for them accordingly. The stations share common spare parts. Economic analysis supports the purchase of new capitalized spare parts. APS was not able to demonstrate the existence of such analyses to Liberty during the audit.

The Saguaro and Ocotillo Power Plants have minimal spare part inventories; APS expenses them as it purchases them. The Navajo Power Plant, operated by SRP, has participated in benchmarking studies of plant inventory. The latest occurred in 2004, using 2003 inventory values. APS states that Navajo shares specific parts that might be requested by fellow members of several industry organizations, as well as with other SRP plants. Equipment redundancy was determined by economic evaluation during the design of the plant.

Liberty examined whether the APS approach in evaluating spare parts inventories appropriately considered the potential need for and cost of replacement power that may be required should parts not be available as needed. Liberty found that APS does perform soundly those economic evaluations that it conducts. However, Liberty did not find that APS has pursued potentially economical approaches; for example:

- The appropriateness of redundancy at Navajo has not been evaluated since its construction
- SRP does not share parts with APS, a joint owner of the project.

[22] Simple payback without the time value of money, Internal Rate of Return, and cost/benefit ratios are all related ways in which the profitability of a project can be measured and compared to other projects.

7. Scheduled Outage Timing

<u>Load Forecasting Uncertainty</u>

APS uses its long-term load forecast for outage scheduling. That load forecast uses econometric modeling for forecasting commercial and industrial loads and end use modeling for residential loads. APS uses a 10-year mean forecast, with a 50 percent probability of being exceeded each year. The industry terms such an estimate a "50/50 forecast." Some utilities and power pools with summer load peaks have moved towards a load forecast that would expected to be exceeded once in 10 years; *i.e.*, the so called 90/10 forecast) because of significant loading strains on the power system.

A 90/10 load forecast can exceed a 50/50 forecast by 5 percent or so. The APS system carries reserves of 12 to 15 percent, and assumes timely completion of scheduled transmission and generation construction. The APS system has been experiencing significant growth – about 300MW per year. APS also recognizes that conditions in the Phoenix Load Pocket can limit the ability to transfer power.[23] However, the use of a 50/50 forecast with the assumption that there will be no delays in new construction can have the effect of eliminating much of the margin for the constrained Phoenix Load Pocket. Designing the system to weather conditions, where the weather itself can cause the load forecast to be exceeded every other year, thus potentially usurping a large portion of system reserves and the margin of the constrained Phoenix Load Pocket (assuming construction is timely completed), can be questioned. For example, if load in the Phoenix Load Pocket exceeds projections by five percent, the effect is the same as having a large unit out of service; *i.e.*, almost half of the capacity reserve in that area is used.

<u>Outage Condition Modeling</u>

APS uses a program called RTSim to simulate conditions of one month and more out to a horizon of three years. The next chapter of this report addresses this program in more detail. RTSim performs hourly dispatch production simulation that incorporates expected loads and known outages. APS uses it to help minimize production costs during scheduled outages. The model discretely treats known planned outages, and probabilistically models forced outages.[24] For periods of less than 30 days, APS looks at the results of RTSim modeling, market data, expected system transmission and generation conditions, and expected loads to fine-tune its bulk power market activity. APS states that its short-term (day-to-day) predictions have been within one percent of what actually occurs.

The outage requirements of the three Palo Verde nuclear units comprise the first building block in long-term outage scheduling at APS. Their outage schedules are a given for purposes of scheduling outages at the remaining stations. The Four Corners, Navajo, and Cholla coal stations are all jointly owned.[25] The outage schedules for the units at these plants[26] must be developed through consensus that meets the needs of all joint owners. This consensus-building process produces a three-year outage schedule that is "cast in stone," and added to the overall outage

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[23] Liberty is unaware if APS specifically models these constraints in their reliability calculations.

[24] When probabilistically modeled, the unit is derated equally in all hours of operation to equate to its forced outage rate.

[25] A jointly owned plant can be one where different utilities own a portion of a unit or different units in total.

[26] The outage schedules consist of major outages, minor outages, and reliability outages at differing frequency levels.

schedule. The availability of skilled workers is a large consideration in the outage scheduling of the base-load coal plants. The outage schedules for the gas plants are determined by run times or starts, economics, and other requirements, such as the skilled labor pool and time requirement for the refurbishment of parts, which in some cases can take up to 6 months. The following table illustrates the timing and layering of major unit coal outages for 2005 on top of the nuclear outage schedule. To the schedule shown, gas plant outages would have to be added.

Table VII.5 APS Coal Unit Major Outages for 2005

Time Period	Units Out	Total MW Out
1/1 – 1/25	-	0
1/25 – 2/18	Navajo #1	105
2/18 – 3/27	Navajo #1, Four Corners #1	275
3/27 – 3/31	Four Corners #1	170
4/1 – 4/18	Cholla #2	260
4/18 – 5/7	Cholla #2, Four Corners #5	373
5/7 – 5/13	Cholla #2	260
5/13 – 9/21	-	0
9/21 – 9/26	Cholla #1	110
9/26 – 11/7	-	0
11/7 – 11/18	Four Corners #4	113
11/18 – 12/31	-	0

Consideration of Market Conditions

The plants have hourly market information available to them. APS M&T trading personnel continuously communicate with personnel at the plants in order to stay abreast of operational and outage conditions. Day-ahead trader reaction to market conditions may initiate these conversations; so may plant personnel knowledgeable of relevant (particularly unexpected) plant conditions. Transitory plant equipment difficulty or market conditions, for examples, can lead to deferrals of outages for repairs to the weekend, if possible. APS uses real-time, 24/7 communication and schedule adjustments to balance the goals of minimizing costs to customers and maintaining safety and equipment integrity. Economy is an important objective, but plant personnel must agree to deferring maintenance in such conditions, in order to assure that decisions fully consider safety and equipment integrity.

8. 2005 Coal Unit Outages

The following table shows 2005 outages of at least two days at APS coal units.

Table VII.6 2005 Coal Unit Outages Exceeding Two Days

Unit and Year Installed	Start	Days	Description
Four Corners #1 – 1963	2/18	40.28	Planned 40 day major boiler overhaul
Four Corners #2 – 1963	4/7	3.60	Backpressure pluggage removal
Four Corners #3 – 1964	5/23	4.59	Superheater tube leak
	7/14	2.99	Reheater tube leak
	11/3	3.49	Reheater tube leak
Four Corners #4 – 1969	1/3	3.09	Waterwall tube leak
	3/7	2.80	Reheater tube leak

	7/15	2.99	Waterwall tube leak
	7/27	3.83	Reheater tube leak
	11/7	10.44	Planned reliability outage
	12/17	2.75	North reserve transformer ground
Four Corners #5 – 1970	1/3	5.12	Reheater tube leak
	4/18	18.31	Minor overhaul (20 day planned)
	5/7	3.82	North main transformer isophase alterations
	6/16	2.62	Reheater tube leak
	8/18	2.82	Waterwall tube leak
	9/20	3.46	Reheater tube leak
	10/9	4.59	Reheater tube leak
	12/1	2.14	Reheater tube leak
	12/17	3.58	North reserve transformer ground
Cholla #1 – 1962	9/21	5.65	Planned mini boiler overhaul
	9/26	2.55	Hydrogen cooler problem on startup
Cholla #2 – 1973	4/1	53.63	41 day planned major overhaul
	10/2	2.67	Boiler tube leak
	12/2	3.19	Boiler tube leak
Navajo #1	1/25	56.37	58 day planned major overhaul
	4/5	2.14	Main steam control valve strainer removal
	11/6	4.05	Waterwall tube leak
Navajo #2	1/1	4.35	Waterwall tube leak
	2/22	3.98	Waterwall tube leak
	9/12	3.12	Waterwall tube leak
	12/14	3.09	Waterwall tube leak
Navajo #3	2/8	2.92	Waterwall tube leak
	2/28	3.04	Spacer tube leak
	5/21	4.54	Superheater tube leak
	6/20	2.64	Superheater tube leak
	9/25	2.64	Waterwall tube leak
	11/22	3.53	Scheduled superheater fouling cleaning

Two causes account for the vast majority of 2005 coal-unit outages: scheduled outages and boiler tube leaks. APS completed all but one scheduled outages within the scheduled window; there was a 12-day extension during the major maintenance outage at Cholla #2. Liberty understands that emergent work (rather than a delay in accomplishing scheduled work) formed the primary cause of the schedule overrun.

The 2005 outages resulting from boiler tube leaks at the coal plants accounted for the need for approximately 272GWh of replacement power. This sum represents 42 percent (272GWh out of a total of 645GWh) of the need for replacement power associated with coal units. The net replacement power cost was $16 million. The table below breaks down this total by unit.

Table VII.7 2005 Replacement Costs Associated With Boiler Tube Leaks

Unit	Size (MW)	Replacement Power (GWh)	Net Replacement Costs ($ Millions)
Four Corners #1	170	-	-
Four Corners #2	170	-	-
Four Corners #3	220	58.4	3.4
Four Corners #4	113	34.4	2.0

Four Corners #5	113	56.2	3.3
Cholla #1	110	-	-
Cholla #2	260	36.5	2.1
Cholla #3	260	-	-
Navajo #1	105	10.2	0.6
Navajo #2	105	36.6	2.2
Navajo #3	105	39.7	2.3
Totals		272.0	15.9

APS has scheduled the Four Corners Unit #3 reheater for replacement in 2006. The reheater at Four Corners Unit #5 is 36 years old; plans for its replacement, however, do not show on the capital expenditure plan out to 2010.

Liberty did not observe an economic analysis comparing the costs of replacing the aging reheater at Four Corners #5 with reduced forced outages for leaks and the accompanying savings that might result in reduced replacement power costs. Those replacement costs are considerable. Similar concerns exist at Navajo #2 and #3. Likewise, Liberty has seen no similar evaluations of boiler equipment replacement at those units.

Liberty's review of the causes of outages having less than 2-day durations revealed that the number of outages caused by operator or maintenance errors appeared unusual. These errors appeared to be concentrated in the operation of Four Corners Unit #3 and Navajo Unit #3. Both APS and SRP have stated that a [redacted]. Liberty also noted that efforts have been made to produce a climate that encourages personnel to discuss issues and problems without fear of job repercussions.

As an example, APS states that there has been an [redacted].[27] APS further states that [redacted]. APS has also stated that an [redacted].[28] APS further states that [redacted]. Such action plans appear to be specifically directed to an individual operator. While individual action may be appropriate, the number of events suggests that the true root cause may include items such as insufficient personnel to allow adequate training time, lack of expectations, or insufficient management support of the overall training process. Liberty would expect that operational errors would not be a problem four years after the installation of a simulator. Liberty believes that the root causes of operational and maintenance errors need review.

[27] APS omitted an additional outage in its response occurring due to operator error at Unit #1 on 3/27/05.
[28] Liberty believes that the installation of the simulator was to address operator and maintenance issues.

9. 2005 Gas Unit Outages

The following table lists 2005 gas unit outages of greater than two days.[29]

Table VII.8 2005 Gas Unit Outages Exceeding Two Days

Unit and Year Installed	Start	Days	Description
Ocotillo #1 – 1960	2/19	41.35	Planned outage
Ocotillo #2 – 1960	2/5	43.32	Planned outage
Saguaro #1 – 1954	2/14	34.71	Planned outage
Saguaro #2 – 1955	2/21	4.58	Maintenance outage
	10/24	17.58	Planned mini overhaul
West Phoenix #1 – 1976	4/16	28.88	Planned minor overhaul
West Phoenix #2 – 1976	2/21	41.25	Hot gas path overhaul
	5/4	2.37	Heat Steam Recovery Generator tube leak
West Phoenix #3 – 1976	3/18	94.28	Generator ground
West Phoenix #4 – 2001	1/1	2.86	Plugged servo
	4/11	4.76	Hot end inspection
	7/17	5.14	Generator bearing repair
	8/29	29.40	HP steam turbine vibration
West Phoenix #5 – 2003			
Steam 5	7/8	2.29	Condenser tube leak
	7/14	2.78	L-O blade inspection
	9/3	2.92	L-O blade inspection
	12/15	2.65	LP blade inspection
CT-5A	4/2	8.60	Combustor inspection
	7/8	2.29	Condenser tube leak
	7/14	2.24	L-O blade inspection
	9/3	2.92	L-O blade inspection
	9/29	4.86	Air cooler leak
	12/15	2.65	Compressor inspection
CT-5B	1/3	2.37	Combustor spread problem
	4/11	2.86	Main gas regulator failure
	7/8	2.29	Condenser tube leak
	7/14	2.24	L-O blade inspection
	9/1	4.92	L-O blade inspection and kettle tube repair
	9/20	2.12	Air cooler tube failure
	10/22	9.75	Planned overhaul
	12/15	2.65	LP blade inspection
Redhawk #1 - 2002			
Steam 1	11/3	10.03	Planned outage
	12/6	9.62	High vibration problem
	12/16	3.57	High vibration problem
	12/21	13.93	High vibration problem

[29] Outages are tracked as outages if unit UAF is affected. The outage may not be an actual outage if it was not called upon to run.

CT-1A	11/3	10.07	Planned outage
CT-1B	11/3	10.10	Planned outage
	12/10	3.36	Replace ST1 potential transformers
Redhawk #2 - 2002			
Steam 2	3/20	5.93	Hot end inspection
	4/1	4.32	Protection relay failure
CT-2A	3/20	5.93	Hot end inspection
	8/7	5.42	Brush failure
CT-2B	3/20	5.93	Hot end inspection
	4/5	2.57	High exhaust temperatures

Small Gas Units[30]

The majority of major outages for the small gas units were planned. Those planned outages appeared to be unusually long. These units have low capacity factors and maintenance is only conducted on a straight time basis. Additionally, parts that are in need of refurbishment are often sent back to the manufacturer, and then reinstalled. This process may lengthen downtime, but it does minimize customer costs, because the units are not needed to run in the dispatch order.

One outage of special interest is the 29-day outage associated with a vibration problem on West Phoenix #4. The steam turbine shaft was found to be warped. APS investigation found that the warping was due to water intrusion and that the water intrusion resulted from a rerouting of drains to an incorrect location during construction. APS replaced the shaft, corrected the routing of the drains, and inspected all other units in the fleet to assure that a similar problem did not exist elsewhere.

Large Gas Units[31]

The new, large gas units all have design problems regardless of their manufacturer. These problems are a result of efforts by each manufacturer to push metallurgical technology, clearances, and operational stability to their limits in order to reduce the heat rates to produce a generating unit that occupies a more economical place in the stack of available resources. All of the large 7,400 BTU/kWh units were designed in this manner; these kinds of design problems are outside of APS control.

West Phoenix #5

West Phoenix #5 is one of approximately 20 new Siemens 501F units in the United States. This category of steam turbines has a blade design problem that can cause the L-O turbine blades (the largest blades) to crack and break.[32] The unit is under an L-O blade inspection mandate (dictated by the manufacturer) after every 1,500 hours of operation.[33] The majority of major outages associated with this unit have arisen from the required inspections of the L-O turbine blades or other required maintenance. Such other outages have generally related to condenser or other leaks. These types of problems are attributed to the cycling duty placed on this unit after it was

[30] Ocotillo #1 and #2, Saguaro #1 and #2, and West Phoenix #1, #2, #3, and #4.
[31] West Phoenix #5, and Redhawk #1 and #2.
[32] This problem has been solved and retrofits are being conducted. Until such retrofits are conducted, strict inspections have been put into place.
[33] Recently increased to 3,000 hours by the manufacturer.

brought into the APS dispatch order in April 2005. This unit was built to run base-loaded, and to remain in a thermally expanded state. Greater cycling causes it to be subjected to more thermal expansion and contraction. The unit is also still undergoing minor outages caused by shakedown issues. To address these problems, APS is actively re-engineering the unit for cycling operation to address these problems. These efforts include collaboration with owners of similar units. An example of re-engineering is the modification of control schemes to eliminate fluctuation of the turbine blades.

APS applies a lost MWh analysis policy that requires a root-cause analysis when any generation is lost at its coal units. APS recently initiated this lost-generation analysis policy at Redhawk, and is considering its implementation at West Phoenix #4 and #5.

Redhawk #1 and #2

The Redhawk units are General Electric 7EA machines. Like the Siemens machines, they too are not designed to be run on a cyclical basis, and suffer generic problems. Compressor rubs from inadequate clearance in the design of the combustion turbines and vibration in the Alstrom generator comprise these generic problems. This vibration problem was not originally found because the old vibration monitoring technology used in the design by Alstrom could not detect the vibration problem. The majority of major outages associated with these units are the required planned inspections based on operational factors. Those planned outages appeared to be longer than they could be. Parts that are in need of refurbishment are often sent back to the manufacturer and then reinstalled.

This approach may lengthen downtime, but does minimize costs. Planned outages take place during off-peak periods where the units are not required to run, which makes outage cost minimization more important than minimization of downtime. Unit #1 also has the vibration problem noted above.[34] Once a new vibration monitoring system was installed and new information obtained, Alstrom designed and installed a correction. In order to minimize forced outage time when the unit is required to run, APS now schedules a short outage approximately one month prior to the regularly scheduled outage, to allow a boroscope inspection of the combustion turbine compressors. More detailed information about turbine compressor condition, which this inspection provides, assists in preparation for the regularly scheduled outage.

Other outages resulted predominantly from condenser or other leaks. These types of problems typify the cycling duty placed on this unit after it was brought into the APS dispatch order in April 2005. This unit was built to run base-loaded, and remain in a thermally expanded state. The unit is also still undergoing minor outages caused by shakedown issues. To address these problems and problems resulting from thermal cycling, APS is actively re-engineering the unit for cycling operation, and is collaboratively working with owners of similar units. An example of re-engineering is that steam injection is being discontinued for greater operational flexibility when cycling the units.[35] APS believes that the small loss of efficiency through discontinuation of steam injection is more than offset by the gains in improved flexibility that results when the units do not experience the metallurgical stress imposed by the steam injection.

[34] This vibration problem has not materialized in Unit #2.

[35] Steam injection is an efficiency process where steam is diverted from the main steam turbine and is reinjected into the combustion turbines.

10. Net Replacement Power Costs

The table below depicts the 2005 replacement power requirements and costs for various segments of the APS system.

Table VII.9 2005 APS Replacement Power Costs

	Replacement Power ($x1,000,000)					
Unit Type	**MWh**	**Cost**	**$/MWh**	**Avoided Costs**	**Net Costs**	**Net $/MWh**
Nuclear	878	67	76	4	63	72
Coal	645	46	71	8	38	59
All Gas	870	77	89	58	19	22
7,400 BTU Gas	760	66	87	50	16	21
Peaking Gas[36]	110	10	91	8	3	27

The table shows that the need to replace low-cost nuclear and coal energy led to the most costly portion of net replacement power costs. It is also noteworthy that the unit costs of replacing power from the intermediate gas units and from the peaking gas units did not differ by more than $4/MWh. These factors indicate a market that is long on supply and comprised largely of gas units. Such conditions would explain relatively small net replacement power cost differentials, because of the replacement of one gas unit with another.

Future conditions may well tend to increase the costs that APS will experience when it must replace base-loaded coal and nuclear generation with gas units. Similarly, the gap between intermediate gas units and peaking gas units on the APS system may also widen as the market tightens in the future. APS is aware of these potential market trends. There is likely to be significant future value in reducing the duration of its gas unit outages.

11. Plant Inspections

On April 4, 2006, Liberty performed a walk through inspection of Units #4 and #5 at the West Phoenix Power Plant. Liberty conducted a similar inspection of Units #1 and #2 at the Redhawk Power Plant on April 5, 2006. West Phoenix #4 (117MW) began commercial operation in 2001 and West Phoenix #5 (506MW) began operation in 2003. Units #1 and #2 at Redhawk (492MW) began operation in 2002. Liberty chose these units for inspection because they:

- Are large and their operation is of significant economic consequence
- As new plants, have experienced significant outages, and account for the bulk of net replacement costs associated with gas plants
- Have had to make the transition from merchant to vertically integrated utility planning and operation.

The primary inspection goal was to identify potential outage contributors. Not all these indicators clearly evidence performance problems, but together comprise a sound list of factors to consider. The indicators include tidiness, unsafe conditions, leaking valves or equipment bushings, other

[36] APS does not calculate the net replacement power costs associated with the outage of its combustion turbines because of the similarity of the replacement fuel.

out of the ordinary conditions, the type of material posted on plant bulletin boards, improperly installed cotter pins, missing bolts, other workmanship issues, impressions of the skill levels of plant operators, and observations about the dedication and values of senior plant personnel.

Liberty made the following observations at both stations:

- No apparent safety conditions
- No bushing oil leaks
- Proper connection of all electrical grounds
- No visible grounding mat problems
- Spare or new equipment, indicating that capital or maintenance projects were underway
- Equipment operating temperatures within normal operating ranges
- No workmanship concerns
- One leaking valve and one fabric heated air joint at West Phoenix Unit #5
- Knowledgeable and enthusiastic plant operators
- Senior plant management review and establishment of specific operation standards and safety expectations regarding plant operations throughout the West Phoenix plant[37]
- Good overall conditions
- No evidence of disrepair or neglect
- Neat and tidy conditions, with no spare equipment cluttering.

The leaking West Phoenix Unit #5 valve could not be repaired until the unit was shut down, at which time APS has scheduled that repair. The fabric-joint problem arose from unit design; APS has been re-engineering it.

Liberty also examined the transmission yards from the fence line. The transmission yards at both plants were neat, tidy, and not cluttered with spare equipment. Liberty observed:

- No apparent safety conditions
- No bushing oil leaks were observed
- Proper connection of all electrical grounds
- No exposed grounding mat material
- Good overall conditions
- No indication of disrepair or neglect.

C. Conclusions

1. The performance metrics of the base-loaded coal units demonstrate effective operation.

The heat rates, capacity factors and availability of the APS coal fired units have been reasonable. Efficiency has increased at the Four Corners Units. The performance metrics for the base-loaded

[37] The West Phoenix Plant Manager was recently transferred from Redhawk where such expectations are in place.

coal plants did not change with the introduction of the former merchant plants into the APS dispatch in April 2005 because the operational costs of the merchant plants were higher.

2. **The performance metrics of the large gas units also demonstrate effective operation; however, performance metrics of these units have been adversely affected by their cycling as part of the APS dispatch order since April 2005.**

The heat rates, capacity factors, and availability of the APS large gas units have been reasonable, considering their modes of operation. However, these units must cycle more than was anticipated in their design. This change has adversely affected their overall performance.

3. **The performance metrics of the less efficient gas units also demonstrate effective operation; however, performance metrics of the large gas units have been adversely affected by their cycling as part of the APS dispatch order since April 2005.**

The less efficient gas units have been moved upwards on the dispatch curve because of the introduction of the APS merchant fleet into the dispatch order. This has resulted in lower net capacity factors for these units, because APS does not call upon them to operate as often. This reduced level of operation also results in higher heat rates, because the units will operate at reduced loads more frequently. The availability metrics have remained relatively unchanged.

4. **The capital expenditure and O&M expenditure patterns for the APS generating fleet have been consistent with operational requirements.**

APS expenditure data indicates that the Company has been making consistent or increasing capital and O&M expenditures at its major plants. The data indicates a marked increase in O&M expenditures at APS coal plants and the former merchant plants. These increased expenditures are reasonable, considering the need to maintain adequately the low cost coal units, and the need to meet the increased maintenance requirements at its gas units because of changes in operating conditions brought about by introduction of the APS merchant fleet into the dispatch order.

5. **APS is not sufficiently reflecting the high net replacement power costs in its economic evaluations related to minimization of outage costs or spare parts procurement.** (*Recommendation #1*)

APS does not sufficiently consider net replacement power costs when it conducts its evaluations of which spare parts to carry and in what amounts. APS does not sufficiently consider these net replacement power costs when it determines whether certain pieces of equipment should be made redundant in order to facilitate on line maintenance or reduce outage time. APS also does not analyze the potential for avoiding net replacement power costs through early replacement of equipment at its power plants and at the Navajo plant operated by SRP.

6. **The use of a 50/50 load forecast, coupled with the fast growth of the Phoenix Load Pocket, and system constraints of the Phoenix Load Pocket, makes achievement of targeted reserves less certain.** (*Recommendation #2*)

The APS system carries system reserves in the order of 12 percent to 15 percent, and assumes that scheduled transmission and generation construction will be completed on time. If such construction slips, then the capacity margin of the Phoenix Load Pocket transfer capability can be significantly affected. Adding weather uncertainties calls into question the ability to achieve consistent reliability levels in the Phoenix Load Pocket under a 50/50 forecast.

7. **The timing and layering of APS unit outage schedules follows industry practice, and is effective.**

APS uses an appropriate hourly-dispatch production simulation program that incorporates expected loads and known outages in order to minimize production costs during outage schedules. APS also considers the operating requirements of all of its generating units, including nuclear, coal and gas fired ones. Especially important are the outage schedules for the gas plants, which are greatly influenced by run times or starts, economics, and other requirements, such as the skilled labor pool and time requirement for the refurbishment of parts. APS also incorporates a sound process for integrating power market conditions into its outage scheduling process, through ongoing communication between plant personnel and power traders. Throughout this process, APS maintains safety and equipment integrity as the prime directive.

8. **Major, scheduled outages at the base load coal plants have had an appropriate length; however, outages at some of these plants from boiler leaks account for a conspicuously high percentage of net replacement power costs associated with these units.** *(Recommendation #3)*

Boiler tube leaks in 2005 accounted for 42 percent (272GWh compared to a total of 645GWh coal replacement power) of the need for replacement power at a cost of approximately $16 million of the $38 million in net replacement power costs for coal units. Studying means for reducing such outages is a worthwhile effort in seeking ways to minimize costs.

9. **The level of operator and maintenance errors at Four Corners Unit #3 and Navajo Unit #3 is high.** *(Recommendation #4)*

APS has recognized the concentration of operator and maintenance errors at Four Corners Unit #3 and Navajo Unit #3, and relied on an action plan of either training or both simulator use and training on a case-by-case basis.

10. **Improving West Phoenix Unit #5 availability is important to the dispatch and keeping net replacement power costs at minimum levels.** (*Recommendation #5*)

West Phoenix Unit #5 is important to dispatch because of its size and the reliability and operational problems associated with its cycling use in the Phoenix Load Pocket. The unit was built to run base-loaded, and remain in a thermally expanded state. That form of operation minimizes the stress of thermal expansion and contraction brought about by cyclical operation. When reliability problems are encountered, not only is power supply in the Phoenix Load Pocket an issue, but power supply from more expensive generating units must be obtained.

11. **APS has appropriately recognized the shift in the market paradigm brought about by inserting the former merchant units into the Company's dispatch order, and is appropriately dealing with Redhawk #1 and #2 and West Phoenix #5 issues involving the units and the need for re-engineering them for intermediate dispatch operation.**

To address the reliability and operating problems of these units, APS is actively re-engineering them for cycling operation, and is collaboratively working with owners of similar units. An example of re-engineering is that control schemes have been modified to eliminate fluctuation of the turbine blades.

APS also is beginning to use at its gas units a lost MWh analysis policy that has been used at coal units. This process involves conducting a root cause analysis when any generation is lost. This lost generation analysis policy was recently initiated at Redhawk, and is being considered for implementation at West Phoenix #5.

12. The large gas units have experienced representative outage frequency and duration, considering their recent in-service dates, generic problems, and the changes in mode of operation.

New generating units, such as the large gas-fired ones, typically have operational problems of the type APS has been experiencing. Generic problems are also typical with new large units, and with units that operate under different conditions from those for which they have been designed. These units were built to run base-loaded and remain in a thermally expanded state and not be subjected to the stress of thermal expansion and contraction brought about by cyclical operation.

D. Recommendations

1. Prepare and execute an action plan that will improve economic evaluations related to minimization of outage time. *(Conclusion #5)*

APS should consider the impacts of net replacement power costs when it conducts its various evaluations related to minimizing outage time. This list of evaluations includes the following:

- Which spare parts to carry and the numbers of these spare parts to carry
- Whether to carry certain pieces of redundant equipment in order to facilitate on-line maintenance or reduce outage time
- Consideration of the benefits of premature replacement of certain equipment.

2. Analyze system reserve calculations using both a 50/50 and 90/10 load forecast, incorporating the constraints of the Phoenix Load Pocket. *(Conclusion #6)*

APS should reevaluate its system reserve calculations by considering both the 50/50 and the 90/10 load forecast methodology, and justify the continued use of the 50/50 load forecast as the optimum means for assuring that desired reliability levels are actually achieved in the Phoenix Load Pocket. This reevaluation should consider impacts that may be caused by slippages in transmission and generation construction, by the fast growth of the Phoenix area, and the load effects of weather conditions that have a 50 percent chance of being exceeded every year.

3. Evaluate the replacement of boiler sections at Four Corners #5, Navajo #2, and Navajo #3 in light of current high net replacement power costs. *(Conclusion #8)*

High replacement power costs from Four Corners #5, Navajo #2 and Navajo #3 boiler tube leaks justify a quantitative evaluation of the effects of replacing boiler sections of these units.

4. Conduct a centralized review of operator and maintenance errors at APS base-loaded coal plants and at Navajo, in order to assure that root causes are being correctly

identified and addressed; determine the reasons why such errors appear to be concentrated at Four Corners Unit #3 and Navajo Unit #3. *(Conclusion #9)*

Operator and maintenance errors appear frequently in APS data as causes of outages. In particular, it is surprising to find a significant level of operational errors four years after the installation of a simulator. The relative costs of reducing such outages may prove quite small; therefore, the root causes of these outages should be examined. Items investigated should include such potential causes as insufficient personnel to allow adequate training time, lack of expectations, or insufficient management support of the overall training process.

5. **Implement for West Phoenix #5 the requirement for root cause analysis when generation is lost.** *(Conclusion #10)*

The root cause analysis used for coal units, and recently used for the Redhawk units, should now be applied to the West Phoenix #5 Unit.

VIII. Purchased Power and Off-System Sales

A. Scope

This chapter of Liberty's report addresses APS's purchased power contracts and off-system sales. Liberty's examination included the following activities:

- Determining the overall magnitude and major counterparties of APS purchases and sales
- Assessment of the off-system sale activities
- Comparison of APS off-system sales with those of other regional utilities in response to Decision No. 68685
- Verification that APS has optimized purchase and sale values from the utility-cost perspective
- Review of a sample of APS's fuel and purchased power contracts for reasonableness and for compliance with the terms and conditions.

B. Power Purchase Findings

1. Regional Conditions

APS's utility native electric load, its generating portfolio and operations, and opportunities for purchases and profitable sales in the marketplace drive the utility's purchased power and sales for resale. Liberty reviewed APS's power contracts and records, and examined summaries of power purchase transactions and sale for resale transactions. APS belongs to the Western Electricity Coordinating Council ("WECC"), whose nearly 1.8 million square-mile operating area includes portions of Canada, Mexico and all or portions of 14 western states. APS's service territory belongs to a sub-region of the WECC known as the Desert Southwest. This sub-region includes portions of Texas, Southern Nevada, New Mexico and Arizona.

WECC reports as of January 1, 2005 for the Desert Southwest sub-region show an excess of capacity at the region's peak and a large amount of excess capacity for virtually every hour of the year. Pertinent WECC-reported data include the following:

- Capacity of 36,917MW
- Load responsibility of 26,262MW
- Average hourly load of approximately 14,000MW.

Low-cost Desert Southwest nuclear, coal, hydro and pumped storage resources comprise approximately 50 percent of the region's capacity. The remainder consists of units with higher running costs. Gas-fired steam and combined cycle units and combustion turbines comprise much of these costlier facilities. Among them, the relatively newer and thermally more efficient combined-cycle units provide approximately 36 percent of available capacity. The region's substantial excess of capacity requires the large number of combined cycle units that have roughly equivalent efficiencies to vie to serve load opportunities on an incremental basis.

2. APS Portfolio

The following table shows the generation and major contract purchase components of the APS portfolio.

Table VIII.1 APS Capacity by Fuel Type

Generation	MW	Percent
Nuclear	1,164	18.1%
Natural Gas	3,411	53.2%
Coal	1,835	28.6%
Solar	5	0.1%
Subtotal	6,415	100.0%
Purchases		
SRP	350	
PacifiCorp	480	
Subtotal	830	
Total	7,245	

APS had a 2005 peak demand of about 7,000MW. APS can serve this load with about 3,000MW from units with low-operating costs consisting of the Palo Verde nuclear, coal, and (to a very small extent) solar units. Meeting the remaining load, however, requires APS to rely on a combination of its combined cycle units and gas-fired combustion turbines, as supplemented by wholesale market transactions. The largest portion of this higher-cost APS capacity comes from new, gas-fired combined cycle units. They total approximately 1,800MW and 28 percent of the Company's total available capacity. APS meets, as is typical of the sub-region, its incremental demand by using gas-fired combined cycle units. The Company, however, is shorter on base-load capacity as compared with the region as a whole. APS therefore can make its relatively inexpensive base-load capacity available for off-system sales less frequently. It must also meet a significantly larger percentage of its peak needs with its more expensive units. The following tables show APS versus regional loads as percentages of base load capacity.

Table VIII.2 APS and Regional Base Load Capacity Ratios

Capacity	Region	Region Less APS	APS
Hourly Load/Base Load Capacity	76%	70%	107%
Load Responsibility/Base Load Capacity	142%	125%	233%

APS obtained a substantial amount of its purchased power from Pinnacle West Energy prior to 2005. This non-utility affiliate operated a number of Arizona merchant generating units. A settlement of the 2003 APS rate case resulted in a transfer of these merchant units to APS, which has placed them into the utility rate base. APS now operates them as an integral part of its utility generation portfolio. This change occurred in 2005, bringing into the APS utility portfolio 1,700MW of additional gas-fired combined cycle plants, including Redhawk #1 and #2 and West Phoenix #4 and #5. APS has also added to its utility generating portfolio 11 combustion turbines, totaling almost 500MW. These units included the Saguaro #3 and the Sundance #1 through #10 units. These additions have altered the Company's power purchase and sale opportunities.

APS has a limited number of: (a) long-term power purchase or sale contracts for a term of greater than one year, and (b) short-term power purchase or sale contracts for a term of less than one year. APS enters into some short-term contracts for price hedging purposes, which Liberty addresses in a separate chapter of this report, titled *Hedging and Risk Management.*

3. APS Purchased Power Contracts

APS has not historically contracted for large amounts of purchased power to meet native load. APS does, however, buy power under two large, important agreements. The largest power purchase contract is with the Salt River Project ("SRP"). This agreement bases the amount of electricity available to APS in large part on customer demand in certain areas served by APS pursuant to a territorial agreement dating from the 1950s and pursuant to supplemental agreements entered thereafter. APS has generating capacity of about 350MW available to it under the contract. SRP may cancel this agreement on three years' notice. APS may also cancel the contract on five years' notice, which may be given no earlier than December 31, 2006. SRP has given notice under this agreement (dated June 7, 2004) of its intent to reduce capacity available to APS by 150MW, effective June 16, 2007.

The second important large purchase power agreement is with PacifiCorp. APS entered into a 30-year seasonal capacity exchange agreement with PacifiCorp in September 1990. APS takes electricity from PacifiCorp during the summer peak season, from May 15 to September 15. APS returns electricity to PacifiCorp during the winter peak season, from October 15 to February 15. APS and PacifiCorp each have 480MW of capacity and a related amount of energy available to them until 2020. Each has the same capacity amounts for their respective seasons. The agreement provides, however, for energy flows that vary from a low of 40 percent load factor to a high of 100 percent. Actual production expense determines the energy price for these transactions.

APS also has less than a dozen small long-term power purchase contracts, which it entered before restructuring in Arizona. Many of these contracts are exchange agreements with small Electric/Irrigation Districts with which APS interconnects.

The following table summarizes historical APS utility purchased power volume and cost data. Non-utility affiliates PWCC and PWEC also made sales to APS before the April 2005 transfer to APS. PWCC also arranged for the sale of some of APS's system output.

Table VIII.3 APS Historical Power Purchases

Year	GWh Purchased	Expense $(000)	$/MWh
2002	7,351	323,417	$43,99
2003	7,389	322,689	$43.67
2004	8,214	412,332	$50.20
2005	6,983	441,487	$63.22

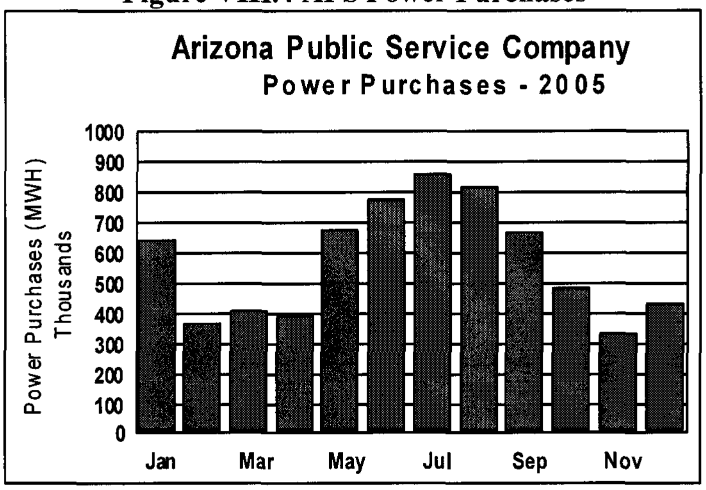
4. Short-Term Purchases for Native Load

APS supplements the output of its generation portfolio and its long-term contract purchases with shorter-term purchases. APS makes these purchases for two primary reasons:

- To purchase market power to serve native load during the May-September peak season
- To hedge APS's exposure to changing market prices in accordance with its hedging policy.

The following table shows APS utility power purchase activity by month for the year 2005. The chart shows that APS traded actively in power purchases and sales. Power purchases increase sharply to meet summer system peak loads. Large peaks in both sales and purchases in January reflect activity under the exchange agreement with PacifiCorp. The increase in purchases during the peak summer months is expected, given that APS must rely on off-system, natural-gas fired generation to meet load during this time.

Figure VIII.4 APS Power Purchases



Liberty's review of individual APS trades, especially with [redacted], shows that APS uses many trades to establish and liquidate hedge positions. For example, of the [redacted] MWh sold to [redacted] for the month of October 2005, [redacted] percent [redacted]. The October 2005 [redacted] transactions include both power purchase and sales, on which APS made $[redacted].

Liberty's review of detailed transaction data shows that about one-half of APS's power purchases and off-system sales occur to establish and liquidate native-load hedges. Hedges accounted for approximately 40 percent of all power purchases and 64 percent of all off-system sales for the period of March 2005 through November 2005.

Liberty also examined the number and volume of APS trades for May 2005. The number of trades per day was low, but the energy volumes reached as high as 30,000MWh per day. This volume is high when compared to APS's approximately 80,000MWh daily average load of May 2005. A review of the specific trades, however, shows that approximately 40 percent of the volume was for the swing call index trades discussed above. Most of the other trades were transactions made for single days in blocks of 25 to 100MW.

5. New Long-Term Power Agreements

A major change in long-term contracts for the purchase of power has resulted from the APS 2005 Settlement Agreement, Decision No. 67744, dated April 7, 2005 ("April 2005 Decision"). The

April 2005 Decision called for APS to acquire Pinnacle West's merchant generation, whose output was being sold to APS to support the utility's load. In lieu of the former capacity and electrical output purchases, APS now has substantially more intermediate and cycling generation assets under utility ownership and operation. These intermediate cycling units replace the need to purchase power from Pinnacle West affiliates, and reduce purchases in the marketplace.

Even so, continuing strong load growth requires frequent additions of new supply sources. APS issued a request for power supply proposals on May 31, 2005. This request for proposals for up to 1,000MW of capacity and energy has been termed the "Reliability RFP." This RFP provides an alternative for securing future power sources. APS has contracted for power as a result of this RFP, with deliveries scheduled to begin in 2007. APS has also issued a separate request for proposals for long-term renewable energy purchase contracts, following the April 2005 Decision. That RFP led to the procurement of renewable power scheduled for delivery beginning in 2007.

C. Off-System Sales Findings

1. Background

APS sells excess energy on an opportunistic basis. The Company includes margins or profits from off-system sales in the PSA mechanism rates. The sources of APS's excess energy include both generation and purchases that prove to be unneeded at times for serving native load.

APS and PWCC keep separate trading books, one for APS utility business, and several others for the PWCC non-utility trading business. APS purchases power to serve a portion of the needs of its utility native load customers, and purchases power to hedge costs for serving such customers. During a given trading day, or for certain longer periods during the year, APS may also have available for off-system sales energy from its owned generating units.

Off-system sales from APS's regulated generating units are generally short-term in nature, for durations of one to six hours and come primarily from generating units already running. APS occasionally arranges for longer-term off-system sales around the APS native load peaks for the low-cost generation already running. The APS available excess generation comes usually from combined cycle generating units fired by natural gas. Consequently, potential sales opportunities face competition from the region's many other similar plants. Its relatively low level of low-cost baseload generation means that APS's low-cost nuclear and coal units serve APS's native load most of the time. APS therefore generally does not have an opportunity for large sales (and higher margins) from its cheaper units, even at low points on its native load curve.

APS generally does not [redacted].

APS provided off-system sales information from monthly PSA reports for the 12-month period from April 2005 through March 2006. APS sold during this period 4,802,761MWh off-system, which produced gross revenue of $318.9 million, or $66.40 per megawatt hour. Gross revenue for PSA off-system sales includes all off-system sales revenue realized, including the liquidation of APS's native load hedges. For financial statement purposes, only the margin realized from the liquidation of native load hedges is recorded as revenue. The following table shows the APS net margin for all off-system sales for this 12-month PSA period and for calendar 2005.

Table VIII.5 APS Off-System Sales Summary

Revenue	**April 2005 to March 2006 PSA**	**Calendar 2005 (Financial)**
Native Load Hedge Liquidation	$163.0	N/A
Other Off-System Sales	$155.9	$58.5
Gross Revenue	$318.9	$58.5
Expenses		
Native Load Hedges	$154.4	N/A
Purchases and APS Generation	$137.3	$46.2
Total Expenses	$291.7	$46.2
Margin		
Liquidation of Native Load Hedge	$8.6	$(7.0)
Other Off-system Sales	$18.5	$12.3
APS Pre-tax Margin	$27.2	$5.3

The period for the data in the two columns differs by three months. The data show that off-system margins for APS vary greatly, depending on natural gas and power market prices. Actual APS margins, as well as any forecasts for APS margins, are highly dependent on the time period in question and the prices for natural gas and power at the time.

2. Sources of Energy for Off-System Sales

The sources of energy for APS's off-system sales fall into three major categories: liquidation of native load hedges, APS purchased power, and excess APS generation. APS makes significant purchases to hedge energy prices for utility native load in accordance with the Company's hedging policy. APS has sometimes made a profit when its hedge positions have been liquidated.

Another source of energy used for APS off-system sales are various sources of purchased power. APS has only two sizable long-term purchase contract arrangements. The first is the Salt River Project Territorial and Power Coordination Agreements, which currently total approximately 350MW of generating capacity, but will drop by 150MW in 2007. The second is the PacifiCorp Exchange Agreement, which allows APS up to 480MW in the summer months only. The earlier, sizeable contracts with PWEC were cancelled following the 2005 summer season, as part of the transition of the former merchant plants to APS ownership and operation. All term contracts that are arranged by APS to serve utility native load (including capacity costs) are recoverable in rates. APS therefore does not include capacity payments for purchased power contracts as an expense in the calculation of margins for off-system sales. Margins for off system sales are calculated using incremental energy costs only.

A third source for off-system sales is excess APS generation. This source is limited because APS's low-cost nuclear and coal serve utility native load nearly all the time. APS can sell its natural gas-fired combined cycle and peaking resources into the marketplace, primarily in the fall, winter and spring seasons. APS assigns its lowest-cost energy, whether from purchases or generation, to its regulated native load first. APS will attempt to re-market any excess power at a profit, if available, in the wholesale market. APS's ability to make high-margin and large volume off-system sales using its gas-fired resources is limited due to competition caused by the Desert Southwest region's significant availability of gas-fired resources with comparable costs.

The table below (compiled from APS PSA Reports to the ACC, April 2005-March 2006) shows the relative size of the off-system sales volumes, revenue, and margins. The following chart shows the buyers and percentages of APS off-system sales during the 2005 calendar year. Gila River, PacifiCorp, and Morgan Stanley were 2005's largest buyers.

Table VIII.6 APS Off-System Sales Sources of Energy and Margins April 2005 – March 2006

Sales Sources	MWh Volume	Revenue $(MM)	Expenses $(MM)	Margin	Revenue/ MWh	Margin/ MWh
Native Load Hedges	2,438,500	$163,023	$154,394	$8,629	$66.85	$ 3.54
Purchased Power	1,717,974	$112,656	$105,185	$7,471	$65.57	$ 4.35
APS Generation	642,602	$ 40,568	$32,854	$7,713	$63.13	$12.00
Mark-to-Market, other[38]	3,685	$ 2,666	$ (695)	$3,361	N/A	N/A
12-month Totals	4,802,761	$318,913	$291,737	$27,175	$66.40	$5.66

Table VIII.7 APS Trading Partners

ENTIRE FOLLOWING TABLE IS CONFIDENTIAL

[redacted]

ENTIRE PRECEDING TABLE IS CONFIDENTIAL

[38] Includes mark-to-market amounts, broker fees, option premiums, and prior period true-ups. Source: response to LCG-3-4

3. Off-System Sales Comparisons to Regional Utilities

On May 5, 2006, the Commission issued Decision No. 68685 in the APS emergency interim rate increase docket. It states:

> *In Decision No. 67744 Staff was directed to commence a review of APS' off-system sales practices within three years of the effective date of the Order. Because of APS' disappointing off-system sales revenues, it is imperative that said review take place as part of the pending permanent rate proceeding...*
>
> *It is Further Ordered that Staff shall commence a review of APS' off-system sales practices as part of the pending permanent rate proceeding, including a comparison of APS' off-system sales revenues and practices with other electricity providers in the West. The review shall also include an analysis of Pinnacle West Capital Corporation, its affiliates and subsidiaries' wholesale energy sales, including, but not limited to, how these wholesale transactions impacted, if at all, APS' off-system sales revenues. The parties will fully explore ways of increasing APS 'off-system sales revenues that will benefit both the Utility and its customers.*

At Staff's request, the audit work sought to address the issues raised by this decision. The analysis had to rely on limited data, because energy providers consider the kind of information underlying these issues to be competitively sensitive. We were able to secure some public information bearing on the issues. It is not certain that all of the sellers that Liberty examined account for off-system sales in the same manner; *e.g.*, APS off-system sales include only short-term sales for the utility, while its non-utility affiliate sales are accounted for separately, and include former long-term contracts of APS, such as with Citizens/UniSource. Off-system sales of the other regional companies generally include long-term contractual sales. Given the limits on available data, the following paragraphs address generally the sources of difference between APS and other regional utilities with respect to off-system sales.

Salt River Project

SRP ("Salt River Agricultural, Irrigation and Power District") is a neighboring electric generator whose service territory is adjacent to and surrounded by APS. SRP operates a sizable electric system; 2005 sales to ultimate customers amounted to around 25 million MWh and sales for resale to almost 12 million MWh.[39]

SRP and its customers benefit from participation in a number of low-cost coal and nuclear generation projects and from purchases of significant amounts of hydro power from the Western Area Power Authority ("WAPA"). The SRP electric supply portfolio produces low power-supply sourcing costs, especially when compared to companies more dependent on gas-fired generation during extremely high-priced periods in natural gas markets (such as 2005). SRP is an owner participant in six coal-fired, multi-plant generation complexes, and owns 654MW of the Palo Verde nuclear complex. SRP has total ownership of over 2,700MW of low-cost coal and nuclear generating capacity in its portfolio. SRP also receives a large allocation of power from WAPA,

[39] 2005 information provided by SRP

which arranges purchases of power from federal government projects. Access to this lower-cost power also helps to reduce SRP's power sourcing costs.

SRP reported off-system sales of 11.87 million MWh and revenues of $616.9 million in 2005. The sales included the liquidation of SRP's native load hedges, excess generation sales, and sales of purchased power.[40] SRP did not provide access to cost information for its generation, but rough estimates could be made from publicly available information from jointly-owned plants and from purchased power information that SRP did provide.

SRP received $51.96 per MWh for its off-system sales in 2005. Liberty estimated a range for SRP's realized margins from these sales. On the lower end of the range, if SRP were to source its off-system sales with its power purchases only, its margin would have been about $84 million in 2005. However, if SRP were to source all of its off-system sales with SRP's average generation costs, the margins would widen to about $230 million. SRP's actual margins realized probably fell within the bounds of this wide range in 2005.

Tucson Electric Power (UniSource)

TEP ("Tucson Electric Power") is another neighboring utility in the Desert Southwest region. TEP has had excess generating capacity for many years, and continues to have substantial generation available for sale to off-system buyers. TEP has about 2,000MW of total generating capacity, of which 1,582 is coal-fired, and has comparably very low operating costs. TEP's 10-K filing with the SEC shows an average production cost per MWh for coal generation of only $17.50 in 2005. Adding in all other sources only increased its average cost to $20.10 per MWh.

TEP generally expects to have excess coal-generating capacity and energy in the first, second and fourth calendar quarters to make sales to wholesale off-system customers. TEP currently has long-term contracts to sell firm capacity and energy to SRP, the Navajo Utility Authority, and the Tohono O'odham Utility Authority. These long-term sales account for approximately 30 percent of TEP's wholesale sales. TEP also sells capacity or energy using short-term forward contracts, typically for one month, three-month or one-year periods, and sells energy in the daily or hourly markets at fluctuating spot market prices.[41]

TEP reported total 2005 revenue from all wholesale sales of about $178 million on 3.182 million MWh of sales, or $55.90 per MWh. TEP's low generating costs made its margins on these 2005 sales very substantial. TEP's financial statements group all wholesale sales together. Taking conservative assumptions for TEP's sourcing costs produces estimated pre-tax margins at around $83 million in 2005. More aggressive assumptions, such as assuming that wholesale sales were made from TEP's coal generation at its average cost, would produce an estimated pre-tax margin of about $118 million. TEP's off-system sales are not voluminous, but likely produced very high 2005 margins because of its low cost of excess generation relative to high 2005 market prices. Those who used natural gas to make off-system sales benefited from those same high market prices for energy, but faced the high fuel prices necessary to operate their units.

[40] Ibid.

[41] TEP 2005 10-K, "Wholesale Business"

PNM Resources

PNM Resources, another regional utility, has had substantial excess generating capacity for a number of years. In fact, some of its excess capacity has been excluded from retail electric rates. PNM Wholesale sells off-system under long-term contracts and short-term sales supported by the unused capacity of Public Service Company of New Mexico's jurisdictional assets and the capacity of PNM's wholesale plants excluded from retail rates. PNM jointly dispatches both utility and non-utility generation in order to improve reliability, provide the most economic power to utility retail customers, and maximize profits on wholesale transactions.[42]

PNM's wholesale operations realized 2005 operating revenues of $628.0 million on sales of 10.59 million MWh, or $59.33 per MWh. Approximately 25 percent of the sales came under long-term contracts; the remaining 75 percent were short-term, off-system sales. PNM reported that the 2005 margin from these wholesale sales was $85.3 million.[43] PNM Wholesale also paid the utility for the transfer of excess power from the utility to PNM Wholesale. Liberty estimates that the utility realized a margin of about $16 million on these transfers.

4. Affiliate Transactions

APS limited 2005 sales to affiliated non-utility operations (PWCC, which engages in wholesale transactions and APSES, which provides retail service) to:

- A balancing agreement associated with several term, wholesale contracts of PWCC
- Sales to optimize transmission capabilities secured as part of a seasonal exchange agreement with PacifiCorp.

Balancing Agreement

APS makes sales to PWCC under a balancing agreement that permits PWCC to match its resources with its requirements to supply a few all-requirements wholesale customers. APS receives a [redacted] under this agreement. APS includes that fee in its monthly PSA filings as "Other Items Accounted For." APS then makes the necessary sales at [redacted]. The following table shows the revenues and expenses of APS under the agreement, separated into two categories:

- Sales for the 2005 months covered by the PSA
- Monthly revenues and expenses through the first quarter of 2006 (to provide a 12-month consecutive period).

[42] PNM Resources 2005 10-K, page A-5

[43] PNM Resources 2005 10-K, pages A-48 and A-49

Table VIII.8 APS Margin on Index-priced Sales made under Balancing Agreement

ENTIRE FOLLOWING CHART IS CONFIDENTIAL

Month	MWH	Fee	Revenue	Total	Expense	Margin
Apr-05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
May-05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jun-05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jul-05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Aug-05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sep-05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Oct-05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nov-05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dec-05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2005 PSA Totals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jan-06	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Feb-06	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mar-06	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2006 YTD Totals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

ENTIRE PRECEDING CHART IS CONFIDENTIAL

<u>Transmission Optimization</u>

APS acquired certain transmission capabilities as part of the seasonal exchange agreement with PacifiCorp, originally concluded in 1990. These facilities provide a transmission path between Four Corners and Borah Brady, a delivery point in Idaho. These facilities enable movement of power from south to north in non-summer months.

In 2005, PWCC found an opportunity to use that transmission path to sell power in the Pacific Northwest. PWCC required additional transmission from Borah Brady to Mid-Columbia or other Pacific Northwest delivery points to take advantage of this market opportunity.

PWCC began to use the Four Corners-to-Borah Brady asset to make its own transactions in 2005. PWCC intended to keep the margins from these sales within the non-utility sector, and did so through October of 2005. After APS personnel noted the existence of the transactions, APS secured changes in how they had been and would be credited, in order to make APS the beneficiary of them. These changes included a crediting of transactions that already closed and assurance that those remaining to be executed would be directly credited to APS. The effect of these changes was to provide APS with the full benefit of the margins produced by the transactions.

PSA accounting therefore already reflects the changes. These transactions have not occurred since March 2006. APS discontinued new arrangements for such transactions, on the ground that their speculative nature made them inappropriate. Acquiring added transmission in order to make distant sales comprised a principal risk factor in taking advantage of the capability of the transmission assets associated with the PacifiCorp exchange. APS also has not permitted PWCC to resume its use. As a result, no party is conducting transactions of this type at present.

The following table shows the magnitude of these transactions in the months where they were substantial.

Table VIII.9 Transmission Optimization Sales

REVENUE, EXPENSE, MARGIN AMOUNTS ARE CONFIDENTIAL

Month	MWH	Revenue	Expense	Margin
Nov-05	49,875	[redacted]	[redacted]	[redacted]
Dec-05	118,246	[redacted]	[redacted]	[redacted]
Jan-06	134,839	[redacted]	[redacted]	[redacted]
Feb-06	52,923	[redacted]	[redacted]	[redacted]
Mar-06	58,800	[redacted]	[redacted]	[redacted]
Totals	414,683	[redacted]	[redacted]	[redacted]

REVENUE, EXPENSE, MARGIN AMOUNTS ARE CONFIDENTIAL

APS has undertaken three measures that address this situation:

- It conducted a review of its other transactions to verify that no other instance of non-utility use of utility assets has taken place
- It has prepared a procedure that will call for ongoing review of transactions by all affiliates to identify any potential cross uses of assets
- It has amended its code of conduct and has drafted supporting policies and procedures to address potential cross-use in the future.

The description given of the transaction review, when coupled with Liberty's survey of transactions by affiliated entities, indicates an appropriate effort to examine the potential for other inappropriate uses of APS resources by the non-utility sector. The code, procedures, and policies have only very recently been filed with the Commission. Moreover, the internal procedure for ongoing review is not yet in place. The pending nature of these other activities makes it impossible to assess their effectiveness at present.

D. Conclusions

1. The trading activities of APS M&T are based on sound hedging policies and procedures, and ensure that the procurement and sale of electric power is conducted in a manner that will meet least-cost dispatch guidelines.

The APS revenue level, prices, and costs of sales and purchases show that power trading has produced economical transactions. There does not appear to be a concentration of sales or purchases with any one trading partner or a discernable pattern of favoring any trading partner.

2. APS effectively utilizes its portfolio of generating resources and power purchases to optimize value in the marketplace.

The APS economic dispatch procedures and operations appear to have operated smoothly since the integration of the merchant generating assets after April 2005. Given the new generation portfolio, APS has been filling in the gaps in resource requirements with appropriate short-term purchases, and with the May 2005 RFP, has supplemented supply resources with additional long-term contracts. APS has also taken advantage of market opportunities inherent in the new generation portfolio to optimize off-system margins in order to reduce PSA costs.

3. **APS has developed the necessary documentation and tools to ensure that electric power trading can be conducted in accordance with the goal of achievement of the least-cost total dispatch.**

The *Forecasting and Modeling* chapter of this report demonstrates that APS does a sound job of providing models and forecasts for regular use of APS M&T. The database is audited regularly by APS, and is available to electric power traders to provide them with accurate and up to date information of costs and availability of APS's own resources so that power transactions that meet the goal of least-cost dispatch can be secured.

4. **APS Internal Auditing has been effective in monitoring the activities of electric power procurement and sale.**

Liberty found that APS internal auditing had conducted sufficient audits of APS M&T to ensure that the appropriate controls and procedures were in place for procurement and sale of electric power for native load customers.

5. **The APS internal documentation separating the activities of utility versus non-utility electric power trading is sufficient, but the external data presented in FERC forms does not make the appropriate distinctions between this information.** *(Recommendation #1)*

Electric power purchase and sale data related to both regulated and unregulated APS activities is not delineated in some publicly available documents, specifically the FERC Form 1.

6. **The APS and non-utility trading operations are not sufficiently physically segregated.** *(Recommendation #1)*

In its on-site visit, Liberty observed that an APS trader and a non-utility trader sit opposite each other on the trading floor. Due to their close proximity, the clear separation of their trading activities is not assured. During the visit, one took a telephone call intended for the other.

7. **PWCC made some inappropriate commitments to trades using utility assets in 2005; but APS has eliminated them, transferred their margins to the utility accounts of APS, and begun changes to prevent the future use of utility assets by affiliates.** *(Recommendation #2)*

Liberty undertook a survey of transactions with affiliates during the PSA's 2005 application and into early 2006, and did not find any other than those associated with the balancing agreement and transmission optimization. There were a number of sales by APS to PWCC under the balancing agreement. APS received appropriate compensation for those transactions and APS structured the agreement to mitigate its risk and to maximize value for its customers. The transmission optimization transactions, however, allowed PWCC to capture margins from the use of utility assets.

APS has corrected the accounting to return to APS the positive margins from those transactions; PSA accounting already credited those margins to customers. APS has initiated a procedure to prevent future problems of this type. It has not yet applied that procedure; therefore, its sufficiency remains to be proven. APS is also in the process of addressing its code of conduct and associated policies and procedures with Staff; this audit's scope did not include an assessment of those documents.

APS does not conduct the transmission optimization transactions that PWCC was entering. Those transactions would require APS to take future market risk; it is appropriate that APS not undertake them at utility customer risk. However, APS has not as yet determined whether there are means for an arrangement that would provide some moderate level of low-risk compensation to PWCC or a third party, in exchange for the right of that party to continue the transactions, which proved profitable in 2005.

8. The primary reason that sales for resale have produced smaller margins than those of neighboring utilities is APS's lower proportional levels of excess coal and nuclear generation.

In today's wholesale electric markets, the greatest opportunity for profits rests with producers who have low-cost coal, hydroelectric or nuclear generation available for sale to the marketplace. Due to the fact that the market price for power is at many times set by combined cycle gas-fired generation in the Desert Southwest and most other U.S. markets, the "black spread" or profit margin on coal and other low-cost generation is substantial.

The key to generating large positive margins on off-system sales is to have a relatively high proportion of low-cost capacity in the portfolio, which expands the periods during which it is available to support off-system sales. Some of APS's neighboring utilities, such as SRP, TEP and PNM, have excess coal generation available for comparatively greater portions of the year. In contrast, APS native load has grown past the company's coal and nuclear resources. These base load resources are needed to serve utility native load all year around, with very limited excess available. APS's "black spread" opportunities will essentially disappear completely in the near future.

APS's positive margins generated by the sale of available combined cycle gas units during off-peak seasons are relatively lower due to their higher costs in relation to market prices, which are set by similar units. The fact that APS's off-system margins are much lower than those of SRP, TEP and PNM is due to these differences in excess supply portfolios.

E. Recommendations

1. Clearly segregate utility and non-utility trading in all operations and reporting to ensure that utility trading is conducted to maximize utility opportunities. *(Conclusions #5 and #6)*

Liberty believes that all data, both public and internal, should be separate and make a clear distinction between the power trading activities of the regulated APS business and the unregulated portion of Pinnacle West's business. APS should have separate and distinct procedures, accounting records, and reports that completely segregate regulated from nonregulated trading activities, and the individuals that conduct this trading activity should be physically separated from each other.

2. **Complete the process of preventing future affiliate use of utility assets and examine means for continuing transmission optimization transactions through some form of sharing mechanism.** *(Conclusion #7)*

PWCC should not have had the opportunity to use utility assets without proper compensation. The methods that APS proposes to prevent such opportunities in the future include a new (but as yet, unused) procedure and the provisions of a code of conduct and associated policies and procedures. Liberty understands that the code, the policies, and the procedures, remain under discussion between APS and the Staff. Liberty's audit did not include a review of them. It is important that the procedure and the code, policies, and procedures adequately address limits on transactions between APS and non-utility affiliated operations.

The transactions at issue cannot make a large difference in PSA calculations; their total margins during their period of heavy use in 2005 and early 2006 was less than $5 million. Moreover, it is not realistic to expect that the utility can capture all of that margin, because it requires taking future market risk. However, depending on the existence of any potential regulatory obstacles (*e.g.*, FERC transmission access requirements), there may be means for APS to capture some portion of those margins without taking such risk. The transactions associated with the balancing agreement, which produced fixed income streams to APS and a sharing of transaction costs/benefits, may provide a model.

IX. Nuclear Fuel

A. Findings

1. Organization

The Palo Verde organization has responsibility for nuclear fuel procurement and management. Palo Verde procedure 05DP-0NF23 identifies the requirements and describes the process for nuclear fuel material contracts. It assigns to the Director, Nuclear Fuel Management primary responsibility for preparing requests for proposals, evaluating bids, negotiating terms, and ensuring the correct execution of nuclear fuel contracts. The administrative procedure covers all the fundamental steps required in a procurement practice. Approval of all nuclear fuel agreements must come from all Palo Verde participants.

The Director, Nuclear Fuel Management, reports to the Vice President – Engineering in the Palo Verde organization. That vice president reports to the chief nuclear officer at Palo Verde. The nuclear fuel management organization has responsibility for nuclear fuel from the initial procurement to spent fuel storage and contains about 100 people. The functions within the organization include:

- Fuel Procurement
- Nuclear analysis
- Transient analysis
- Reload analysis
- Reactor engineering
- Fuel services (movement of fuel into and out of the reactors)
- Projects.

The Manager, Nuclear Fuel Procurement, leads the procurement function. Somewhat more than two years ago, APS ended dual reporting of this manager. He previously reported also to the APS fuel procurement organization but now reports solely within the Palo Verde organization. He still draws upon APS services such as the law department and the insurance management department. The procurement group contains six people reporting to the manager.

2. The Nuclear Fuel Cycle

The nuclear fuel cycle consists of the integrated set of activities necessary to take uranium ore from production to disposal. The key procurement elements in that cycle include:

- Securing uranium in the form of ore or concentrates
- Converting the material to concentrate it in the form of uranium oxide, or "yellowcake"
- Enriching the material to make it useable as a fuel for generating electricity
- Fabrication of the fuel into assemblies that can be placed into the reactor for electricity generation.

Uranium, a slightly radioactive metal, exists in most rocks and soils, in many rivers, and in seawater. A number of the Earth's regions have ground concentrations of uranium at levels sufficient to make extraction of it for use as nuclear fuel economical. Extraction of these concentrations of ore takes place through underground or open pit mining. Natural uranium consists, primarily, of a mixture of two isotopes (atomic forms) of uranium. Only 0.7% of natural uranium is "fissile," or capable of undergoing fission, the process by which energy is produced in a nuclear reactor. The fissile isotope of uranium is uranium 235 (U-235). The remainder is uranium 238 (U-238).

Uranium milling extracts the uranium from the ore. Milling produces the uranium oxide concentrate; *i.e.*, yellowcake, which contains more that 80 percent uranium. Additional processing through enrichment prepares the uranium for use as fuel. This process requires uranium to be in gaseous form. Enrichment strips away the U-238 isotope, and increases the concentration of the fissile isotope, U-235, from about 0.7 percent in natural uranium to between three and five percent.

Palo Verde's reactor fuel is in the form of ceramic pellets encased in metal tubes to form fuel rods, which are arranged into assemblies containing 236 rods. The manufacturer controls precisely the dimensions of the fuel pellets and other components of the fuel assembly to ensure consistency in the characteristics of fuel bundles. Inside a nuclear reactor, the nuclei of U-235 atoms split (fission) and release energy that is used as a source of heat in a nuclear power station in the same way that the burning of coal, gas, or oil is used as a source of heat in a fossil fuel power plant.

As the fission process proceeds over time, the concentration of fission fragments and heavy elements formed in a fuel assembly will increase to the point where it is no longer practical to continue to use the assembly. After about 18 months, APS removes some of the "spent" fuel from each reactor. With the three units at Palo Verde, and an 18-month refueling cycle for each unit, APS typically conducts two refueling outages each year, one in the spring and one in the fall.

When removed from a reactor, a fuel assembly will be emitting both radiation, principally from the fission fragments, and heat. Used fuel is unloaded into a storage pool adjacent to the reactor to allow the radiation levels to decrease. The water in the pools shields the radiation and absorbs the heat. Used fuel can be held in such pools for several years.

In addition to the Palo Verde fuel storage pools, APS is operating a facility for on-site dry storage of spent nuclear fuel. With the existing storage pools and the addition of the new facility, APS believes spent nuclear fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit.

3. APS Nuclear Fuel Agreements

APS used to contract separately for the uranium, conversion, enrichment, and fabrication elements of the Palo Verde nuclear fuel cycle. It has now combined the four cycle elements into [redacted]

- [redacted]
- [redacted]

The [redacted] resulted from an RFP under which APS solicited individual and combination bids for these elements. APS then analyzed the combinations that would produce the greatest net economy. The Company found that [redacted].

Price escalation provisions are typical of contracts for these four elements of the fuel cycle. Some use market prices. [redacted].

Table IX.1 [redacted] Contract Pricing

Contract	[redacted] Portion	[redacted] Portion	[redacted] Basis
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

The use of broad economic measures such as GDP, base prices, labor costs, and materials costs has left APS price changes generally consistent with overall inflation, with some protection reflected by the portion of the original prices that remain fixed. Recently, nuclear fuel cycle prices, after a period of depression, have increased at greater rates. Therefore, contracts with market-based escalation provisions, all other things equal, would lately have produced more significant increases. The following table shows market prices for comparable months in 1997 and 2005, as taken from a trade publication, *Ux Weekly*.[44] The last column shows that prices have remained strong, as shown on the publisher's web site (uxc.com) at May 12, 2006.

Table IX.2 Nuclear Fuel Cycle Market Price Trends

Element	April 1997	April 2005	Increase		May 2006
U3O8 (lb)	$11.97	$22.50	$10.53	87.97%	$41.50
Conversion (kgU)	$5.97	$12.00	$6.03	101.01%	$11.50
UF6 (kgU)	$29.95	$70.00	$40.05	133.72%	$119.93

The [redacted] agreements cover [redacted]:

- End of xxxx
  - [redacted] of reactor requirements for uranium concentrates
  - [redacted] of reactor requirements for conversion services
- End of [redacted]
  - [redacted] of reactor requirements for enrichment services
- End of [redacted]
  - [redacted] of reactor requirements for enrichment services
- End of [redacted]
  - [redacted] of reactor requirements for fabrication services.

[44] Volume 11, Issue 14, April 7, 1977 and Volume 11, Issue 14, April 2005

Accordingly, APS has secured all of its reactor requirements for a period beginning well before and extending well beyond 2005. APS has negotiated a contract with [redacted] to supply [redacted] percent of Palo Verde's enriched uranium requirements starting in 2011. APS's analysis shows that this contract produces favorable terms and will diversify the nuclear fuel supply chain in the future.

4. APS Variable Nuclear Fuel Costs

APS expenses the costs of nuclear fuel using the unit-of-production method, which amortizes costs based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense. APS also charges nuclear fuel expense for the permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel, and it charges APS $0.001 per kWh of nuclear generation.

APS determines the amortization rate for each group of fuel assemblies that it inserts and removes from the reactor at the same time. The rate is simply the remaining cost (original cost less amortization to date) divided by the difference between the estimated thermal output and the actual thermal output to date. The table below shows the generation, fuel costs determined by applying the amortization rate, and the resulting unit cost of production for APS's share of all Palo Verde units.

Table IX.3 Nuclear Generation and Fuel Costs

Nuclear Generation and Fuel – APS			
Month	**MWh**	**Fuel Costs**	**¢/kWh**
Mar-05	[redacted]	[redacted]	[redacted]
Apr-05	[redacted]	[redacted]	[redacted]
May-05	[redacted]	[redacted]	[redacted]
Jun-05	[redacted]	[redacted]	[redacted]
Jul-05	[redacted]	[redacted]	[redacted]
Aug-05	[redacted]	[redacted]	[redacted]
Sep-05	[redacted]	[redacted]	[redacted]
Oct-05	[redacted]	[redacted]	[redacted]
Nov-05	[redacted]	[redacted]	[redacted]
Dec-05	[redacted]	[redacted]	[redacted]

The monthly summary of PSA Report fuel costs submitted by APS contains an amount for nuclear fuel costs that is greater than that shown above because it includes an amount for the amortization of the dry spent fuel storage facility, ISFSI ("Independent Spent Fuel Storage Installation").

The nuclear fuel production costs (¢/kWh) for these months varied from the lowest to the highest by 24 percent. For all other forms of generation for these same months, the variability was 89 percent. The average nuclear production cost was 0.51 ¢/kWh, while that for all other APS generation was more than six times greater at 3.16 ¢/kWh. During the period shown on the table above, nuclear fuel costs made up only 5.2 percent of APS's total generation fuel costs.

5. Fuel Accounting

APS uses FERC accounting for nuclear fuel costs.

6. Non-Generation Sensitive APS Nuclear Fuel Costs

Liberty's audit scope did not include an examination of the impacts of plant operations and their appropriateness on APS's nuclear fuel costs. However, Liberty was able to isolate the critical and dominant element in costs that do not vary with production. The APS method for amortizing nuclear fuel costs, described above, applies the following formula.

$$\mathbf{(A-B)/(C-D) = ExF = G}$$

The components of that formula are:

- A: Original costs including AFUDC
- B: Amortization recorded to date
- C: Estimated Life in terms of thermal energy megawatt days
- D: Actual thermal energy megawatt days to date
- E: Cost per remaining thermal energy megawatt days
- F: Actual thermal energy megawatt days for the month
- G: Amortization.

APS calculates a separate "A" component for each fuel-assembly batch loaded into each of the three Palo Verde units. APS makes that calculation essentially contemporaneously with the loading of each fuel batch, which occurs at approximately 18-month intervals for each unit. Once calculated, the "A" component remains essentially fixed for the approximately 18-month interval across which amortization (the "G" component) for that batch takes place. Costs under the fuel cycle contracts form the overwhelming portion of the "A" costs of each batch, supplemented by the addition of some (far lesser) costs associated with APS activities related to fuel cycle work. Liberty found this "A" component to be the best benchmark for assessing nuclear fuel costs independently of outages at the units. The following table shows the recent costs for the "A" components at Palo Verde and the current estimate for the next such component.

Table IX.4 Fixed Portion of Palo Verde Fuel Costs

ENTIRE FOLLOWING TABLE IS CONFIDENTIAL

Measure	Cycle Number		
	Twelve	Thirteen	Fourteen
Unit 1			
Date	[redacted]	[redacted]	[redacted]
Assemblies	[redacted]	[redacted]	[redacted]
Cost	[redacted]	[redacted]	[redacted]
Yearly Change	[redacted]	[redacted]	[redacted]
Unit 2			
Date	[redacted]	[redacted]	[redacted]
Assemblies	[redacted]	[redacted]	[redacted]
Cost	[redacted]	[redacted]	[redacted]
Yearly Change	[redacted]	[redacted]	[redacted]
Unit 3			
Date	[redacted]	[redacted]	[redacted]
Assemblies	[redacted]	[redacted]	[redacted]
Cost	[redacted]	[redacted]	[redacted]
Total Unit Change	[redacted]	[redacted]	[redacted]
Total Plant			
Total Plant Costs	[redacted]	[redacted]	[redacted]
Yearly Change	[redacted]	[redacted]	[redacted]
Period Change	[redacted]	[redacted]	[redacted]

ENTIRE PRECEDING TABLE IS CONFIDENTIAL

B. Conclusions

1. APS conducts nuclear fuel procurement and management through an effective organization.

The unique requirements of the nuclear fuel cycle, and the criticality of handling, analysis, planning, and other technical issues makes it appropriate to assign the function to the organization dedicated to the units' operations. APS has provided for dedicated, experienced leadership and staffing of nuclear fuel procurement and contract administration, and has linked it effectively with the other organizations having important interfaces.

2. APS has developed and used effective procedures for procuring nuclear fuel.

The procedures address procurement activities. APS has procured long-term agreements through competitive bids, which APS solicited on a broad and flexible basis, and which APS evaluated on the basis of best cost, considering options for combining contracts for some cycle elements. The pricing structure that APS chose has proven beneficial in keeping nuclear fuel costs in line with more general measures of inflation, rather than with the more significant increases experienced recently in the nuclear fuel market.

A comparison of the current, prior, and next fuel loads for each unit confirms that there have been only nominal changes in those costs for fuel loads that are not sensitive to unit generation levels.

3. APS uses an appropriate basis to account for its nuclear fuel costs for ratemaking purposes.

Accounting is based on FERC Accounts 120.1 through 120.5.

C. Recommendations

Liberty does not have any recommendations in the area of nuclear fuel management.

X. Financial Audit of PSA Costs

A. Scope

This chapter of Liberty's report addresses the APS financial process for assembling, preparing, and submitting the monthly Power Supply Adjustor ("PSA") filings to the ACC. Liberty undertook the following activities and reviews as part of this examination:

- PSA Overview
- Accounting Systems
- PSA Filing Policy and Procedures
- General Review of PSA Monthly Filings
- Detail Review and Testing of August 2005 PSA Filing
- PSA Over/Under Recovery Filings
- Impact of Supplemental Charges or Refunds.

B. Findings

1. PSA Overview and Guidelines

An August 18, 2004 Settlement Agreement and Decision No. 67744 at Docket No. E-01345A-03-0437 resolved issues related to an APS application to increase rates. Section IV of that agreement provided for a PSA designed to track changes in the Company's cost of obtaining power supplies; *i.e.*, the difference of the going forward costs of fuel and purchased power (capped at an annual amount of $776.2 million) compared to costs embedded in APS's base rates. The decision set the base rate of fuel at $0.020743 per kWh and the initial Adjustor Rate at zero, with annual April 1 resets, beginning with 2006. The main components of the PSA include:

- An incentive/risk sharing mechanism sharing of costs or savings (90/10: customers/Company)
- A bandwidth limiting the change in the Adjustor to +/- $0.004 per kilowatt hour
- A balancing account to track recoverable or refundable amounts during the current period
- A balancing account surcharge mechanism separate from the adjustor to clear the accumulated recoverable or refundable amount for purposes of resetting the balance to zero
- Making customers the beneficiaries of benefits of all off-system sales margins through a credit to the PSA.

APS must maintain accounting records and reporting statements through a set of processes that provides adequate comfort about completeness and accuracy to those who rely upon them. Maintaining adequate internal controls and reporting measures allows those who rely upon the books and records and reports to have reasonable assurances that they can use them to form opinions and make judgments concerning financial, regulatory, and operational compliance. APS's accounting and reporting records thus form an integral, necessary part in assuring compliance with the PSA.

2. Accounting Systems

APS maintains its books and records in accordance with the FERC's Uniform System of Accounts ("USofA") which the ACC has adopted. APS has its own accounting system and set of books. APS's computerized accounting system known as "GECA" is approximately nine years old, and consists of approximately twelve different accounting modules. The accounting system's main module, the general ledger, serves as the central element for financial reporting purposes. A number of accounting interface modules; *e.g.*, payroll and accounts payable, have links to this general ledger module. The current system has "*detail general ledger*" reporting capabilities, which enables it to generate, on an account-by-account basis, reports that provide summary descriptions of each accounting entry transaction. The capability includes the provision of appropriate cross references, cost center codes, and relevant dollar value transactions, among others.

The general ledger system also provides the capability to "drill down" through the transaction to explore the underlying supporting information. The accounting system also includes the capability to download information into PC-based worksheet programs, such as Microsoft Excel, which can support a variety of sub-reports and analyses. The Company currently is evaluating a new accounting system from PeopleSoft, which is a leading provider of applications designed for large, complex business operations, many of them utilities.

APS M&T uses a proprietary system (called "TranZ" and discussed more extensively earlier in this report) to control fuel and energy deal information. TranZ tracks power and natural gas transactions from deal entry to settlement and reporting. TranZ also allows the use of Microsoft Excel worksheets and various Microsoft Access queries, which APS uses for detailed analysis and sub-reporting.

3. PSA Filing Policy and Procedures

APS filed with the ACC on June 6, 2005 an initial "Plan of Administration ("POA"), which provides the basis for the filing of monthly PSA reports. The APS POA describes the process that APS used for 2005 and early 2006 for calculating the applicable monthly PSA kWh sales and related fuel and purchased power costs, including benefits of off-system sales, which the PSA filings must include. The APS Regulatory Department had initial responsibility for assembling and filing PSA reports with the ACC. APS transferred this responsibility to its Fuel Forecast and Analysis Department in October 2005. This department prepares the required monthly filings, taking assistance from the Generation Accounting Department, the Financial Accounting Departments, the Generation Business Services Department and the APS M&T BackOffice (the "PSA Team"). APS submits all monthly reports under a certified statement by a responsible company official.

The ACC Staff submitted its POA on March 20, 2006. APS used this POA to guide its March 30, 2006 monthly PSA filing. Liberty understands that the purpose of the Staff POA was to define more clearly the scope and framework of the PSA, and to provide for the inclusion of the monthly/annual filing requirements minimally necessary to comply with the PSA, as approved by the ACC.

Liberty conducted an examination of the APS procedures for preparing its PSA filings. Liberty requested that APS provide a detailed narrative description of the process used to develop, assemble, review, authorize, and submit fuel and power purchase information in the PSA filings. APS provided a copy of the POA as submitted by the ACC Staff on March 20, 2006. Liberty found that APS has yet to prepare formal, written processes and procedures. APS personnel commonly reported to Liberty that the current, unwritten processes were developed after consultation with members of the responsible Company departments, in order to assure its completeness and accuracy.

4. General Review of Monthly PSA Filings

The PSA has been designed to track changes in the Company's cost of obtaining power supplies; *i.e.*, the difference between: (a) the going forward costs of fuel and purchased power (capped at an annual amount of $776.2 million), and (b) the base rate of $0.020743 per kWh embedded in APS's base rates beginning in April 2005. Liberty examined the Company's financial information collection and reporting processes to test the accuracy and reasonableness of APS's compliance with ACC reporting requirements. Liberty also examined entries for the major cost elements that the PSA includes; *e.g.*, fuel and energy procurement, power plant reliability, fuel usage, purchased power, off system sales, and hedging transactions.

APS submitted monthly compliance reports under its POA from June 6, 2005 until the March 30, 2006 report, which APS prepared in accord with the Staff POA. The APS monthly filings have required the filing of both confidential and non-confidential information. The non-confidential or publicly available information required under both of the POAs includes the following:

- Balancing Account calculations
- Total power and fuel costs
- Customer sales in kWh and dollars by customer class
- Number of customers by customer class
- Detailed listing of items excluded from PSA calculation
- Detailed listing of any adjustments to the adjustor reports
- Total off-system sales revenues
- System losses in MW and MWh
- Monthly maximum retail demand in MW
- Identification of Company contact person and phone number.

The confidential information required under each POA basically remained the same providing for the following:

- For each Generating unit
    - Net generation, in MWh per month, and 12 months cumulatively
    - Average heat rate, both monthly and 12-month average
    - Equivalent forced-outage rate, both monthly and 12-month average
    - Outage information for each month, including event type description, start and end dates

  - Total fuel costs per month
  - Total fuel costs per kWh per month
- Power purchases
  - Quantity purchased in MWh
  - Demand purchased in MW to extent specified in contract
  - Total costs for demand to extent specified in contract
  - Total cost of energy
- Off-system sales
  - Itemization of off-system sales margins by buyer
  - Details on negative off-system sales margins
- Natural Gas Purchases
  - Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel
  - Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer-term purchases, including price per therm, total cost, supply basis, and volume by contract
- Monthly projection for next 12-month period showing estimated (Over)/Under-collected amounts. (As provided for in Staff POA, APS began providing this information with January 2006 data.)
- Summary of unplanned outage costs by resource type. (As provided for in Staff POA, APS began providing this information with December 2005 data).

The defined and allowable PSA costs include prudently incurred fuel and purchased power costs incurred to provide service to retail customers, including direct costs of contracts used for hedging system fuel and purchased power. APS captures and reports the allowable costs under the following accounts from the FERC USofA:

- 501 Fuel – Steam
- 518 Fuel – Nuclear less ISFSI regulatory amortization
- 547 Fuel – Other production
- 555 Purchased Power
- 565 Wheeling – Transmission of Electricity by Others.

There are a number of PSA exclusions. ACC Decision No. 66567 provided APS the ability to recover reasonable and prudent costs associated with customers who left APS standard offer service, including those under special contract rates, but then returned to APS. The PSA provides that a direct assignment or special adjustment may be applied to recognize the cost differential between the power purchases needed to accommodate the returning customer, and the power supply cost component of otherwise applicable standard-offer rates. Additionally, purchases under specific terms on behalf of standard-offer special contract customers may also be directly assigned. Schedule E-36 customers are also directly assigned power supply costs based on APS system incremental costs at time of consuming power.

5. Review and Testing of August 2005 PSA Filing

Liberty selected the month of August 2005 as a representative period for a test of PSA filings. APS submitted the August 2005 confidential data to the ACC on November 1, 2005 in accordance with the Settlement Agreement approved by Decision No. 67744. APS used its POA to guide this filing. The confidential filing consisted of a 12-page document that included a cover sheet, financial data, and a certification by the Company, as required under the agreement.

The filing's major elements included:

- Fuel and fuel generation; *i.e.*, gas, oil, coal, and nuclear to also include revenues from gas hedges and mark-to-market expense
- Purchased power; *i.e.*, long-term, market purchases, and other purchases
- Revenues from off-system sales.

The sum of these elements reflects native load costs. Dividing this sum by the kWh of energy to serve native load produces the cost per kWh. This cost for August 2005 was $0.025762. The supporting schedules provide an additional level of data to assist for simple monthly reviews; however, the underlying fuel and purchase power costs, including off-system sales data related to each is contained within APS's accounting systems, including the APS M&T TranZ system. APS's Plant Purchase and Generation ("PP&G"), Plant Net Generation Report sets forth other relevant data such as kWh generated. The generation information contained in the PSA filing lists only APS's share; the PP&G reports provide both Total Generation and APS share basis.

Given the lack of formal, written procedures for the preparation of the PSA filings, Liberty used working meetings with the PSA team representatives to obtain a description of the relevant processes, including the sources and uses of detailed supporting data. APS personnel described relevant accounting entries as follows:

- Fuel cost consumed or used in the production of steam generation is booked to Account 501 Fuel; this account includes the costs of coal, oil, and gas consumed or burned to generate steam and the handling costs for each.
- Residual waste related to these fuels is also booked to Account 501.
- The cost of fuel (including freight and handling) when first purchased is initially booked to Account 151, Fuel Stock; when consumed the cost is credited from this account and then charged to Account 501.
- APS books the costs of nuclear fuel consumed in the production of power to Account 518; inventory accounts are also used, first debited when acquired and then credited when consumed and charged to Account 518.
- Account 547 fuel includes the cost of fuel delivered at the station used in other power generation. This account also includes summary transactions for gas hedges and mark-to-market expenses; the primary supporting data for the underlying transactions is maintained by APS M&T through its TranZ reporting programs.

APS provided a detail general ledger summary transaction report for August 2005 in support of activities for each of these accounts. APS uses this report as the primary source data for preparation of the PSA filings. APS secures kWh generated data from the PP&G Plant generation report. The information contained therein includes all related transactions, and included the following information:

- Charge Number: a source code posting reference to include general description of the transaction
- Operational Identification: generating station and unit#
- Process: description of fuel type
- Amount (or expense).

Liberty selected specific (sometimes multiple) transactions of each relevant type for more detailed review. This testing sought to trace data back to the core or originating documents associated with the transactions being tested.

Liberty tested transactions for "Purchased Power," whose costs APS books to Account 555. These costs include long-term, market, other purchases, and off-system sales. Liberty found that the lack of written procedures necessitates a considerable amount of review and analysis in order to verify proper classification for PSA reporting purposes. APS derives the values it reports from a number of sources, which include a report titled "Level Three Purchased Power and Fuel," supported by information from APS M&T. A report titled "Power Marketing Detail," which APS M&T supports, supplemented by information from a PP&G report entitled "Purchase Power Supply" serves as the source of kWh captured as purchased power. Liberty's sampling of specific purchase-power transactions included one of the largest off-system sales transactions, an APS M&T short-term physical gas purchase on the spot market, and a short-term purchase and sale of gas.

6. PSA Over/Under Filings

Pursuant to Decision No. 67744, APS provides a non-confidential PSA report on a monthly basis. The filing consists of approximately five schedules, which set forth the applicable retail energy costs subject to PSA consideration, a subtraction of retail energy costs recovered under base rates, and a remainder, which consists of those costs considered to comprise the pre-sharing over/under recovered cost value. Only 90 percent of the pre-sharing over/under recovery value is considered as potentially recoverable. The current monthly value is added to the prior month's balance, and an interest charge is calculated against that balance and added to the total cumulative value. The calculation is repeated and tracked on a monthly basis through the 12-month PSA period. The filing also provides customer count, sales in kWh, and revenues by customer class on a monthly and cumulative basis through the 12-month PSA period. This non-confidential filing is also certified by an officer of the Company.

The total PSA energy cost is calculated as follows:

- The book fuel and purchased power costs less off-system sales produce the Native Load Power Supply Costs
- The PSA retail energy cost results from multiplying the ratio of the PSA retail energy kWh sales to total native load energy kWh sales by the Native Load Power Supply Costs
- Retail base energy cost is simply determined by multiplying the PSA retail energy kWh sales times the $.020743 base rate per kWh

- Subtracting the retail base energy cost from the calculated PSA retail energy costs to determine the pre-sharing over/under recovery value.

7. Railroad Rates

APS became involved in a 1997 rate case proceeding before the Surface Transportation Board. APS received a favorable ruling related to fuel transportation rates for deliveries of coal to its Cholla Power Plant. In 2003, the case was reopened, after which the railroad, BNSF, secured an increase in rates between May 23, 2003 and December 2004. APS was required to pay $[redacted] in February 2005. APS made an accrual adjustment on its books at year-end 2004, booking $[redacted] APS entered the sum total of $[redacted] as a payable due to BNSF. APS stated that this adjustment has not affected the PSA since all entries were for periods before the effective date of the PSA.

Effective [redacted] APS and BNSF [redacted]. APS owns three of the four Cholla generating units; its [redacted] APS did not book any portion to inventory because the fuel received during these time periods would have already been burned. APS notes the entry does affect the PSA as it relates to a period after the effective date.

C. Conclusions

1. APS's accounting systems are adequate and reasonably maintained to provide the necessary collection, reporting, and auditing of the PSA filings, and provide for reasonable testing.

Liberty reviewed APS's current accounting and reporting systems. Liberty also examined and tested the capabilities of APS's accounting and reporting systems during its detailed documentation and testing process. The Company follows the FERC USofA, has adequate controls and accounting policies and procedures in place, and subjects the underlying collection and reporting of data to internal and external audits. The internal audit group has been actively involved in conducting reviews on many of the fuel and purchased power elements contained within the PSA.

2. APS audits, however, have yet to address PSA filing preparation. *(Recommendation #1)*

Liberty confirmed that no internal audits had yet been conducted on APS's in-house procedures and sources for developing the monthly PSA reports to the ACC. Even though PSA filings began fairly recently (early 2005), Liberty believes that it is timely to begin periodic examination of those filings and the processes supporting them, given the importance in assuring their completeness and accuracy.

3. APS documents its filing information well, but lacks a formal written procedure addressing preparation of the monthly PSA filings. *(Recommendation #2)*

Liberty requested that APS provide a detailed narrative description of the process used to develop, assemble, review, authorize, and submit fuel and power purchase information in the PSA filings. Interviewees expressed some level of agreement that such a procedure should be developed. Due to the lack of such a formal procedure, Liberty took an oral description of the process, as provided by the PSA team representatives, and undertook testing of the completeness and accuracy of that process to verify it was appropriate, well understood, and followed. Liberty's testing found the information in the filing to be well documented and supported.

4. The monthly PSA filings were in general compliance with filing requirements and the sum total of costs were reasonably accurate.

Liberty requested and obtained copies of the confidential and non-confidential information for all of the PSA reports, beginning with the initial information for March 2005. Liberty reviewed the monthly filings for:

- General compliance with the POA filing requirements
- Mathematical accuracy
- Quality of detail schedules supporting the filing.

In general, monthly information submitted was consistent with the requirements of the POAs in effect at the time, *i.e.,* the Company's beginning on June 6, 2005 and Staff's as filed on March 20, 2006. Liberty notes that on February 28, 2006 the Company submitted a combined filing which included both December 2005 and January 2006 data. This step was taken to provide more timely data; *i.e.*, within 30 days of the close of the period. Additionally, December 2005 data reflected the first time the Company included a projected 12-month period showing estimated (Over)/Under-collected amounts. January 2006 data reflected the first summary of unplanned outage costs by resource type. These steps moved the Company more closely into compliance with the Staff's March 20, 2006 POA filing requirements.

5. Despite their general accuracy, including the total costs of generation, APS over- or under-stated individual coal, oil, and gas generation costs due to a misclassification of costs among the three types of generation. *(Recommendation #3)*

Liberty tested a number of the filings for mathematical accuracy, and found minor discrepancies. These minor differences in part are related to tracing supporting schedule information to the monthly summary page that lists the various fuel and purchased-power cost elements contained within the PSA format.

The first page of the PSA filing provides a summary of each of the cost elements, which include, for example: (a) gas generation, (b) gas generation tolling arrangements, (c) gas hedges and mark-to-market expenses, (d) oil generation, (e) coal generation, and (f) nuclear generation, the sum of which comprises the total Generation Fuel Expense. The underlying cost of each of these items is supported in greater detail in a supporting schedule identified as "Plant Capability, Generation, Fuel Costs, Heat Rate and EFDR for APS Generation". This schedule provides plant generation and costs by fuel type and generating unit.

Liberty found that the sum total of Generation Fuel Expense on the summary schedule agreed with the sum total on the detail supporting schedule just described. However, Liberty found it difficult to cross-reference some cost elements on an individual basis. For example, it took only a straightforward process for Liberty to determine that the sum of the nuclear cost activity on the supporting schedule tied to the summary schedule. Liberty found the same for gas hedges and mark-to-market expenses. However, Liberty could not match the summary costs for gas, oil, and coal generation line items to the supporting schedule.

Liberty's detailed analysis of the August 2005 data revealed that coal generation costs reported on the detail schedule included fuel oil and gas expenses, which are used as a supplement to coal. The detail schedule also listed a separate line item for coal handling costs; Liberty expected that the sum of these would reflect the total costs of coal generation expenses. However, when coal generation was reported on the summary page, the ancillary fuel oil and gas cost was removed, and the sum was reported as coal generation. The fuel oil cost used for coal generation was then included in the oil generation mix, which Liberty construes as a misclassification. In a similar misclassification, gas used for coal generation was reported under gas generation costs. In sum, while the totals may be accurate, some minor improvements in presentation may be warranted for easy tracing of expenses on a cost element basis to correct for these misclassifications of generation.

The remaining purchased power costs items, such as long-term purchases, market purchases, other purchases, and revenues from off-system sales, were easy to trace from the summary schedule back to supporting schedules. The sum of these costs produces the net native load fuel and purchased power expenses, which are then divided by the associated energy in kWh to serve native load customers, producing a unit cost per kWh. While each of the supporting expense schedules discussed earlier also reflects the corresponding kWh for each item, there is no mechanism or process for efficiently providing a summary of each to verify the sum total of kWh energy. For example, the summary page has just two columns. The first provides a description of the major component. Each row therefore lists the major element; *e.g.*, gas-generation fuel expense or oil-generation fuel expense. The second column provides the corresponding dollar cost value of each. A simple solution would be to add a third column "kWh energy" to which the corresponding kWh values would be entered for each respective element, such as gas, oil, coal generation, purchase power, and sales.

6. Liberty's detail testing of August 2005 PSA data found the supporting information to be well documented and reasonably consistent with the values reported.

Liberty found no inaccuracies that would materially affect the accuracy of cost totals as reported, and found only minor discrepancies. As noted in the previous conclusion, such discrepancies do not affect the total costs of generation, but do cause APS to overstate or understate individual coal, oil, and gas generation costs due to a misclassification of costs among the three types of generation.

Liberty was able to verify the accuracy of the underlying information back to the individual transaction level; however, the process was made more cumbersome by the lack of a formal narrative or written procedure. Excluding the previously noted exception dealing with the treatment of natural gas and oil used in coal plants, Liberty was able to verify and tie-in the total costs reported for each element within the PSA filing. With the exception of fuel oil, Liberty examined the underlying supporting data in order to test individual transactions in each of the various costs elements. Liberty excluded fuel oil from testing because the approximately $50,000 costs were nominal.

Liberty found that the APS August 2005 data included brokers' fees for Gas and Purchase Power of $34,515 and wheeling costs of $2,087,952. Liberty succeeded in tracing these costs items to supporting documents; however, the June 6, 2005 POA did not clearly provide for the inclusion of such costs. Staff's March 20, 2006 POA does support the inclusion of wheeling costs, which Liberty finds consistent with the purpose and nature of PSAs generally. Liberty's review of later PSA over/under filings indicates that APS has removed the cost of brokers' fees, and thereby resolved that matter. This adjustment was reflected in APS's December 2005 over/under filing account balance as submitted on February 28, 2006. The Company's potential recovery of the account balance is currently pending; therefore, customers will only be responsible for the balance approved.

7. **Liberty's detail review of the non-confidential PSA Over/Under values found them to be accurate, but they should be more transparently supported.** *(Recommendation #4)*

Liberty performed the same kind of review of the August 2005 non-confidential over/under recovery filing as it did for the confidential filing for that month. This review found the over/under recovery filing to be accurate.

Liberty started with the premise that the source data contained within the confidential filing; *i.e.*, total system fuel and purchased power costs along with other supporting information contained therein would provide the necessary data to arrive at the book fuel and purchased power costs reflected on the non-confidential filing. This proved not to be the case. One of the weaknesses of the confidential filing is that it does not provide sufficient data to perform this calculation. As discussed earlier, the Company did not have a written procedure to guide or explain how the values in the non-confidential filing are developed.

Liberty requested that the PSA team prepare a schedule that would begin with the August 2005 confidential filing information, and list the supporting adjustments to arrive at the values presented on Schedule 1 in the non-confidential filing. In a working session with the PSA team, Liberty was able to verify that the underlying adjustments to the August 2005 confidential data reasonably support the values reflected in the August 2005 non-confidential filing.

8. **A review of APS handling of supplemental fuel charges and refunds indicates that supplemental charges and refunds have been accounted for in the PSA when applicable; the accounting methods are not consistent for purposes of recording refunds, but the inconsistency has not had a material impact on the PSA.** *(Recommendation #5)*

Liberty found APS's consideration and rationale for booking supplemental charges and refunds to be reasonable. Supplemental charges and refunds should be booked in a manner that tracks as closely as possible the impact such events would have had on the product had it been correctly priced at the time.

In the case of the $[redacted] for the [redacted], APS correctly considered and balanced its accounting entries, assigning a portion as a direct charge to expenses and a portion to inventory. This method appropriately matched the time when the product would have been put into inventory and then ultimately consumed. For example, the [redacted]. Based upon normal target inventory levels, it is reasonable to assume that the [redacted] deliveries would have already been consumed, while a portion of the more recent [redacted] deliveries would still be in inventory. The correct approach would be to book a portion to both expense and inventory. Liberty also agrees that this transaction would have no effect on the PSA and precedes the effective date.

The [redacted]. APS booked all of the costs as [redacted] to expense. Liberty found it reasonable to book the $[redacted]; therefore, the associated inventory would more than likely have already been burned. Liberty questions, however, the APS accounting for the $[redacted] period. Recording that as [redacted] ignores the fact that a portion of the [redacted] purchases would still be presumed to be in inventory when the entry was recorded. Liberty believes that, from an accounting perspective, the more appropriate entry would have been to book a portion of the [redacted], rather than to book it all as [redacted]. This split method would more accurately correspond to purchase-to-consumption activity.

That said, however, Liberty also found that APS's method did not materially affect the PSA. Had APS recorded the entry as proposed by Liberty the refund would merely have taken longer to flow through the monthly PSA filings, and would more than likely have been fully refunded by the end of the annual PSA period.

D. Recommendations

1. **Conduct periodic internal audits of the PSA filings to verify the soundness, completeness, and accuracy of the activities that produce them, with the first such audit to be conducted as part of the next audit plan.** (*Conclusion #2*)

Liberty understands that the PSA filing process recently began in early 2005, but believes that periodic audits of the PSA filings is important in assuring their completeness and accuracy and in building confidence in the PSA mechanism.

2. **Develop a written policy and procedure for the preparation of the confidential PSA filings.** (*Conclusion #3*)

The PSA filings require input from five different departments. The development of a formal policy and procedure would assist in assuring that the filings are complete and prepared consistently. A written procedure also provides assistance for those employees who may need to prepare such filings in the absence of ones currently assigned that task. Liberty, discussed the matter with the Company, and understands that it is in general agreement and is in the process of preparing a formal written procedure.

3. **Correct PSA reporting methods to assure more accurate classification and reporting of coal, oil, and gas generation information.** *(Conclusion #5)*

While the total costs of generation may be accurate, the individual coal, oil, and gas generation costs either were over or understated due to a misclassification of costs between the three types of generation.

4. **Revise the PSA confidential filing format to provide a sufficient level of detail to support the calculation of the components contained within PSA non-confidential filing.** *(Conclusion #7)*

The confidential filings should provide support for the fuel and purchase power costs and energy sales levels contained within the non-confidential filing. This process would be more transparent, and assist the ACC Staff in evaluating the underlying costs and determining how such costs ultimately affect the values in the balancing account.

5. **Closely review and monitor adjustments to fuel costs to assure that supplemental charges and refunds appropriately consider the impact on inventory values and fuel expenses for financial reporting purposes.** *(Conclusion #8)*

Supplemental charges or refunds should be booked in a manner which tracks as closely as possible the impact such events would have had on the product had it been correctly priced at the time. A consistent policy applying such principals on a monthly basis provides a reasonable presentation for financial reporting purposes.